UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Fiscal Year Ended December 31, 2004

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

or the Transition Period from to

Commission File Number	Registrant, State of Incorporation, Address and Telephone Number	I.R.S. Employer Identification No.
1-8809	SCANA Corporation (a South Carolina corporation) 1426 Main Street, Columbia, South Carolina 29201 (803) 217-9000	57-0784499
1-3375	South Carolina Electric & Gas Company (a South Carolina corporation) 1426 Main Street, Columbia, South Carolina 29201 (803) 217-9000	57-0248695
1-11429	Public Service Company of North Carolina, Incorporated (a South Carolina corporation) 1426 Main Street, Columbia, South Carolina 29201 (803) 217-9000	56-2128483

Securities registered pursuant to Section 12(b) of the Act:

Each of the following classes or series of securities is registered on the New York Stock Exchange.

Title of each class	Registrant
Common Stock, without par value	SCANA Corporation
5% Cumulative Preferred Stock par value $50 per share .	South Carolina Electric & Gas Company

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark whether the registrants: (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

SCANA Corporation ☐
South Carolina Electric & Gas Company ☐
Public Service Company of North Carolina, Incorporated ☒

Indicate by check mark whether the registrants are accelerated filers (as defined in Exchange Act Rule 12b-2).

SCANA Corporation Yes ☒ No ☐
South Carolina Electric & Gas Company Yes ☐ No ☒
Public Service Company of North Carolina, Incorporated Yes ☐ No ☒

The aggregate market value of voting stock held by non-affiliates of SCANA Corporation was $4.0 billion at June 30, 2004, based on a price of $36.37. Each of the other registrants is a wholly owned subsidiary of SCANA Corporation and has no voting stock other than its common stock. A description of registrants' common stock follows:

Registrant	Description of Common Stock	Shares Outstanding at February 18, 2005
SCANA Corporation	Without Par Value	112,909,904
South Carolina Electric & Gas Company	$4.50 Par Value	40,296,147(a)
Public Service Company of North Carolina, Incorporated	Without Par Value	1,000(a)

(a) Held beneficially and of record by SCANA Corporation.

Documents incorporated by reference: Specified sections of SCANA Corporation's 2005 Proxy Statement, in connection with its 2005 Annual Meeting of Shareholders, are incorporated by reference in Part III hereof.

This combined Form 10-K is separately filed by SCANA Corporation, South Carolina Electric & Gas Company and Public Service Company of North Carolina, Incorporated. Information contained herein relating to any individual company is filed by such company on its own behalf. Each company makes no representation as to information relating to the other companies.

Public Service Company of North Carolina, Incorporated meets the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and therefore is filing this form with the reduced disclosure format allowed under General Instruction I(2).

TABLE OF CONTENTS

DEFINITIONS

The following abbreviations used in the text have the meanings set forth below unless the context requires otherwise:

TERM	MEANING
AFC	Allowance for Funds Used During Construction
CAA	Clean Air Act, as amended
DHEC	South Carolina Department of Health and Environmental Control
DOE	United States Department of Energy
DOJ	United States Department of Justice
DT	Dekatherm (one million BTU's)
DTAG	Deutsche Telekom AG
Energy Marketing	The divisions of SEMI, excluding SCANA Energy
EPA	United States Environmental Protection Agency
FERC	United States Federal Energy Regulatory Commission
Fuel Company	South Carolina Fuel Company, Inc.
GENCO	South Carolina Generating Company, Inc.
GPSC	Georgia Public Service Commission
IRC	Internal Revenue Code, as amended
IRS	Internal Revenue Service
KW or KWh	Kilowatt or Kilowatt-hour
LLC	Limited Liability Company
LNG	Liquefied Natural Gas
MCF	Thousand Cubic Feet
MGP	Manufactured Gas Plant
MMBTU	Million British Thermal Units
MMCF	Million Cubic Feet
MW or MWh	Megawatt or Megawatt-hour
NCUC	North Carolina Utilities Commission
NMST	Negotiated Market Sales Tariff
NRC	United States Nuclear Regulatory Commission
NSR	New Source Review
NYMEX	New York Mercantile Exchange
PRP	Potentially Responsible Party
PSNC Energy	Public Service Company of North Carolina, Incorporated
PUHCA	Public Utility Holding Company Act of 1935, as amended
Santee Cooper	South Carolina Public Service Authority
SCANA	SCANA Corporation, the parent company
SCANA Energy	A division of SEMI which markets natural gas in Georgia
SCE&G	South Carolina Electric & Gas Company
SCG Pipeline	SCG Pipeline, Inc.
SCH	SCANA Communications Holdings, Inc., a subsidiary of SCI
SCI	SCANA Communications, Inc.
SCPC	South Carolina Pipeline Corporation
SCPSC	The Public Service Commission of South Carolina
SEC	United States Securities and Exchange Commission
SEMI	SCANA Energy Marketing, Inc.
SFAS	Statement of Financial Accounting Standards
Southern Natural	Southern Natural Gas Company
Summer Station	V. C. Summer Nuclear Station
Transco	Transcontinental Gas Pipeline Corporation
Williams Station	A. M. Williams Generating Station owned by GENCO
WNA	Weather Normalization Adjustment

PART I

ITEM 1. BUSINESS

CORPORATE STRUCTURE

SCANA CORPORATION

A holding company owning the significant direct, wholly-owned subsidiaries listed below

SOUTH CAROLINA ELECTRIC & GAS COMPANY
Generates and sells electricity to wholesale and retail customers and purchases, sells and transports natural gas to wholesale and retail customers.

SOUTH CAROLINA GENERATING COMPANY, INC.
Owns and operates Williams Station and sells electricity to SCE&G.

SOUTH CAROLINA FUEL COMPANY, INC.
Acquires, owns and provides financing for SCE&G's nuclear fuel, fossil fuel and sulfur dioxide emission allowances.

PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INCORPORATED
Doing business as PSNC Energy, purchases, sells and transports natural gas to retail customers.

SOUTH CAROLINA PIPELINE CORPORATION
Purchases, sells and transports natural gas to wholesale and industrial customers. Owns and operates two LNG plants for the liquefaction, storage and regasification of natural gas.

SCG PIPELINE, INC.
Provides transportation of natural gas in Georgia and South Carolina.

SCANA COMMUNICATIONS, INC.
Provides fiber optic telecommunications, ethernet services and data center facilities and builds, manages and leases communications towers in South Carolina, North Carolina and Georgia.

SCANA ENERGY MARKETING, INC.
Markets natural gas, primarily in the Southeast, and provides energy-related risk management services to producers and customers. Through its SCANA Energy division, markets natural gas in Georgia's retail natural gas market.

SERVICECARE, INC.
Provides service contracts on home appliances and heating and air conditioning units.

PRIMESOUTH, INC.
Provides management and maintenance services for power plants and a synfuel production facility.

SCANA SERVICES, INC.
Provides administrative, management and other services to the subsidiaries and business units within SCANA Corporation.

SCANA and each of its direct, wholly-owned subsidiaries are incorporated under the laws of the State of South Carolina. In addition to the subsidiaries above, SCANA owns two other energy-related companies that are insignificant and one additional company that is in liquidation.

RISK FACTORS

The risk factors that follow relate in each case to SCANA Corporation and its subsidiaries (SCANA), and where indicated the risk factors also relate to South Carolina Electric and Gas Company and its consolidated affiliates (SCE&G) or Public Service Company of North Carolina, Incorporated and its subsidiaries (PSNC Energy) or both.

Commodity price changes may affect the operating costs and competitive positions of SCANA's, SCE&G's and PSNC Energy's energy businesses, thereby adversely impacting results of operations, cash flows and financial condition.

Our energy businesses are sensitive to changes in coal, gas, oil and other commodity prices. Any changes could affect the prices these businesses charge, their operating costs and the competitive position of their products and services. SCE&G is able to recover the cost of fuel used in electric generation through retail customers' bills, but increases in fuel costs affect electric prices and, therefore, the competitive position of electricity against other energy sources. In the case of regulated natural gas operations at SCE&G and PSNC Energy, costs for purchased gas and pipeline capacity are recovered through retail customers' bills, but increases in gas costs affect total retail prices and, therefore, the competitive position of gas relative to electricity, other forms of energy and other gas suppliers. Increases in gas costs may also result in lower usage by customers unable to switch to alternate fuels.

SCANA, SCE&G and PSNC Energy are subject to complex government rate regulation, which could adversely affect revenues and results of operations.

SCANA, SCE&G and PSNC Energy are subject to extensive regulation which could adversely affect operations. In particular, SCE&G's electric operations in South Carolina, and SCANA's gas operations in South Carolina (including SCE&G) and North Carolina (PSNC Energy), are regulated by state utilities commissions. Our gas marketing operations in Georgia are also subject to state regulatory oversight. Although we believe we have constructive relationships with our regulators, our ability to obtain rate increases that will allow us to maintain reasonable rates of return is dependent upon regulatory discretion, and there can be no assurance that we will be able to implement rate increases when sought. Moreover, in connection with SCANA's acquisition of PSNC Energy, PSNC Energy agreed not to seek a general rate increase until after August 2005.

SCANA, SCE&G and PSNC Energy are vulnerable to interest rate increases and may not have access to capital at favorable rates, if at all, which would increase borrowing costs and adversely affect results of operations, cash flows and financial condition.

Changes in interest rates can affect the cost of borrowing on variable rate debt outstanding, on refinancing of debt maturities and on incremental borrowing to fund new investments. SCANA's business plan, and the business plans of SCE&G and PSNC Energy, reflect the expectation that we will have access to the capital markets on satisfactory terms to fund commitments. Moreover, the ability to maintain short-term liquidity by utilizing commercial paper programs is dependent upon maintaining investment grade debt ratings. The liquidity of SCANA, SCE&G and PSNC Energy would be adversely affected by unfavorable changes in the commercial paper market or if bank credit facilities became unavailable at acceptable rates.

SCANA may not be able to reduce its leverage as quickly as planned. This could result in downgrades of SCANA's debt ratings, thereby increasing its borrowing costs and adversely affecting its results of operations, cash flows and financial condition.

SCANA's leverage ratio of debt to capital increased significantly following its acquisition of PSNC Energy in 2000, and was approximately 58% at December 31, 2004. SCANA has publicly announced its desire to reduce this leverage ratio to between 50% to 52%, but SCANA's ability to do so depends on a number of factors. If SCANA is not able to reduce its leverage ratio, SCANA's debt ratings may be affected, it may be required to pay higher interest rates on its long- and short-term indebtedness, and its access to the capital markets may be limited.

Operating results may be adversely affected by abnormal weather.

SCANA, SCE&G and PSNC Energy have historically sold less power, delivered less gas and/or received lower prices for natural gas in deregulated markets, and consequently earned less income, when weather conditions are milder than normal. Mild weather in the future could diminish the revenues and results of operations and harm the financial condition of SCANA, SCE&G and PSNC Energy. In addition, severe weather can be destructive, causing outages and property damage, adversely affecting operating expenses and revenues.

Potential competitive changes may adversely affect gas and electricity businesses due to the loss of customers, reductions in revenues, or write-down of stranded assets.

The utility industry has been undergoing dramatic structural change for several years, resulting in increasing competitive pressures on electric and natural gas utility companies. Competition in wholesale power sales has been introduced on a national level. Some states have also mandated or encouraged competition at the retail level. Increased competition may create greater risks to the stability of the utility earnings of SCE&G and PSNC Energy generally and may in the future reduce earnings from retail electric and natural gas sales. In a deregulated environment, formerly regulated utility companies that are not responsive to a competitive energy marketplace may suffer erosion in market share, revenues and profits as competitors gain access to their customers. In addition, SCANA's and SCE&G's generation assets would be exposed to considerable financial risk in a deregulated electric market. If market prices for electric generation do not produce adequate revenue streams and the enabling legislation or regulatory actions do not provide for recovery of the resulting stranded costs, a write-down in the value of the related assets could be required.

SCANA, SCE&G and PSNC Energy are subject to risks associated with changes in business climate which could limit access to capital, thereby increasing costs and adversely affecting results of operations, cash flows and financial condition.

Factors that generally could affect our ability to access capital include general economic conditions and our capital structure. Much of our business is capital intensive, and achievement of our long-term growth targets is dependent, at least in part, upon our ability to access capital at rates and on terms we determine to be attractive. If our ability to access capital becomes significantly constrained, our interest costs will likely increase and our financial condition and future results of operations could be significantly harmed.

SCANA, SCE&G and PSNC Energy do not fully hedge against price changes in commodities. This could result in increased costs, thereby resulting in lower margins and adversely affecting results of operations, cash flows and financial condition.

SCANA, SCE&G and PSNC Energy enter into contracts to purchase and sell electricity and natural gas. We attempt to manage our exposure by establishing risk limits and entering into contracts to offset some of our positions (i.e., to hedge our exposure to demand, market effects of weather and other changes in commodity prices). We do not hedge the entire exposure of our operations from commodity price volatility. To the extent we do not hedge against commodity price volatility or our hedges are not effective, results of operations, cash flows and financial condition may be diminished.

A downgrade in the credit rating of SCANA, SCE&G or PSNC Energy could negatively affect its ability to access capital and to operate its businesses, thereby adversely affecting results of operations, cash flows and financial condition.

Standard & Poor's Ratings Services (S&P), Moody's Investors Service (Moody's) and Fitch Ratings (Fitch) rate SCANA's long-term senior unsecured debt at BBB+, A3 and A-, respectively. The S&P and Fitch ratings carry a stable outlook while the Moody's rating outlook is negative. S&P, Moody's and Fitch rate SCE&G's long-term senior secured debt at A-, A1 and A+, respectively, with a stable outlook at S&P and Fitch and a negative outlook at Moody's. S&P and Moody's rate PSNC's long-term senior unsecured debt at A- and A2, respectively, with a stable outlook. Fitch does not rate PSNC. If S&P, Moody's or Fitch were to downgrade any of these long-term ratings, particularly to below investment grade, borrowing costs would increase, which would diminish financial results, and the potential pool of investors and funding sources could decrease. S&P and Moody's rate the short-term debt of SCE&G and PSNC at A-2 and P-1, respectively, and Fitch rates the short-term debt of SCE&G at F-1. If these short-term ratings were to decline, it could significantly limit access to the commercial paper market and other sources of liquidity.

Changes in the environmental laws and regulations to which SCANA, SCE&G and PSNC Energy are subject could increase costs or curtail activities, thereby adversely impacting results of operations and financial condition.

SCANA's, SCE&G's and PSNC Energy's compliance with extensive federal, state and local environmental laws and regulations requires us to commit significant capital toward environmental monitoring, installation of pollution control equipment, emission fees and permits at our facilities. These expenditures have been significant in the past and are expected to increase in the future. Changes in compliance requirements or a more burdensome interpretation by governmental authorities of existing requirements may impose additional costs on us or require us to curtail some of our activities. Costs of compliance with environmental regulations could harm our industry, our business and our results of operations and financial position, especially if emission or discharge limits are reduced, more extensive permitting requirements are imposed or additional substances become regulated.

Changing regulatory and energy marketing structures could affect the ability of SCANA and SCE&G to compete in our electric markets, thereby adversely impacting results of operations, cash flows and financial condition.

Federal energy legislation and FERC's regulatory initiatives, if enacted as currently proposed, would bring sweeping changes to the country's existing regulatory framework governing transmission, open access and energy markets and would attempt, in large measure, to standardize the national energy market. Any rules standardizing the markets could have a significant impact on SCE&G's access to or cost of power for its native load customers and for its marketing of power outside its service territory. At this time, management is unable to predict the final rules or timing of implementation of such standardization and the resultant impact on results of operations, cash flows and financial condition.

Repeal of PUHCA could adversely impact business by increasing costs or otherwise changing or restricting the nature of activities in which SCANA, SCE&G and PSNC Energy may engage. Any such changes could thereby impact results of operations, cash flows or financial condition.

SCANA is a registered holding company under PUHCA. In recent years, repeal of PUHCA has been proposed, but it is unclear whether or when such a repeal would occur. It is also unclear to what extent repeal of PUHCA would result in additional or new regulatory oversight or action at the federal and state levels, or what the impact of those developments might be on SCANA's business or that of SCE&G or PSNC Energy.

Problems with operations could cause us to incur substantial costs, thereby adversely impacting results of operations, cash flows and financial condition.

As the operator of power generation facilities, SCE&G could incur problems such as the breakdown or failure of power generation equipment, transmission lines, other equipment or processes which would result in performance below assumed levels of output or efficiency. The failure of a power generation facility may result in SCE&G purchasing replacement power at market rates. These purchases are subject to state regulatory prudency reviews for recovery through rates.

Covenants in certain financial instruments may limit SCANA's ability to pay dividends, thereby adversely impacting the valuation of our common stock and our access to capital.

Our assets consist primarily of investments in subsidiaries. Dividends on our common stock depend on the earnings, financial condition and capital requirements of our subsidiaries, principally SCE&G and PSNC Energy. Our ability to pay dividends on our common stock may also be limited by existing or future covenants limiting the right of our subsidiaries to pay dividends on their common stock. Any significant reduction in our payment of dividends in the future may result in a decline in the value of our common stock. Such a decline in value could limit our ability to raise debt and equity capital.

A significant portion of SCE&G's generating capacity is derived from nuclear power, the use of which exposes us to regulatory, environmental and business risks. These risks could increase our costs or otherwise constrain our business, thereby adversely impacting our results of operations, cash flows and financial condition.

The V.C. Summer nuclear plant, operated by SCE&G, provided approximately 5.5 million MWh, or 21% of our generation capacity, in 2004. As such, SCE&G is subject to various risks of nuclear generation, which include the following:

- The potential harmful effects on the environment and human health resulting from a release of radioactive materials in connection with the operation of nuclear facilities and the storage, handling and disposal of radioactive materials;
- Limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with our nuclear operations or those of others in the United States;
- Uncertainties with respect to contingencies if insurance coverage is inadequate; and
- Uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of their operating lives.

The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance, the NRC has the authority to impose fines or shut down a unit, or both, depending upon its assessment of the severity of the situation, until compliance is achieved. Revised safety requirements promulgated by the NRC could necessitate capital expenditures at nuclear plants such as ours. In addition, although we have no reason to anticipate a serious nuclear incident, if a major incident should occur at a domestic nuclear facility, it could harm our results of operations, cash flows and financial condition. A major incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or licensing of any domestic nuclear unit. Finally, in today's environment, there is a heightened risk of terrorist attack on the nation's nuclear facilities, which has resulted in increased security costs at our nuclear plant.

ORGANIZATION

SCANA, a South Carolina corporation having general business powers, was incorporated in 1984, and registered as a public utility holding company under PUHCA in 2000. SCANA holds, directly or indirectly, all of the capital stock of each of its subsidiaries except for the preferred stock of SCE&G. SCANA and its subsidiaries had full-time, permanent employees as of February 18, 2005 and February 13, 2004 of 5,549 and 5,458, respectively. SCE&G was incorporated under the laws of South Carolina in 1924, and is an operating public utility. SCE&G had full-time, permanent employees as of February 18, 2005 and February 13, 2004 of 2,775 and 2,865, respectively. Prior to being acquired by SCANA in 2000, PSNC Energy was incorporated under the laws of North Carolina in 1938. PSNC Energy is now incorporated under the laws of South Carolina, and is an operating public utility in North Carolina with full-time, permanent employees as of February 18, 2005 and February 13, 2004 of 705 and 775, respectively.

INVESTOR INFORMATION

SCANA's, SCE&G's and PSNC Energy's annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed with or furnished to the SEC are available free of charge through SCANA's internet website at *www.scana.com* as soon as reasonably practicable after these reports are filed or furnished. The information found on SCANA's website is not part of this or any other report filed with or furnished to the SEC.

SEGMENTS OF BUSINESS

SCANA does not directly own or operate any physical properties. SCANA's significant, wholly-owned subsidiaries are engaged in the functionally distinct operations described below. SCANA also has an investment in one LLC which owns and operates a cogeneration facility in Charleston, South Carolina. SCANA also owns two other energy-related companies that are insignificant and one company that is in liquidation.

Information with respect to major segments of business is contained in Management's Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G and the consolidated financial statements for SCANA and SCE&G (Note 11) and PSNC Energy (Note 9). All such information is incorporated herein by reference.

Regulated Utilities

SCE&G is a regulated public utility engaged in the generation, transmission, distribution and sale of electricity and in the purchase and sale, primarily at retail, of natural gas. SCE&G's business is subject to seasonal fluctuations. Generally, sales of electricity are higher during the summer and winter months because of air conditioning and heating requirements, and sales of natural gas are higher in the winter months due to heating requirements. SCE&G's electric service area extends into 24 counties covering more than 15,000 square miles in the central, southern and southwestern portions of South Carolina. The service area for natural gas encompasses all or part of 34 of the 46 counties in South Carolina and covers more than 22,000 square miles. The total population of the counties representing the combined service area is more than 2.8 million. Resale customers include municipalities, electric cooperatives, investor-owned utilities and federal and state electric agencies. Predominant industries in the areas served by SCE&G include synthetic fibers, chemicals, fiberglass, paper and wood, metal fabrication, stone, clay and sand mining and processing and textile manufacturing.

GENCO owns and operates Williams Station and sells electricity solely to SCE&G.

Fuel Company acquires, owns and provides financing for SCE&G's nuclear fuel, fossil fuel and sulfur dioxide emission allowance requirements.

PSNC Energy is a public utility engaged primarily in purchasing, selling and transporting natural gas to approximately 409,000 residential, commercial and industrial customers (as of December 31, 2004). PSNC Energy provides service to its 28 franchised counties covering approximately 12,000 square miles in North Carolina. The industrial customers of PSNC Energy include manufacturers or processors of textiles, chemicals, ceramics and clay products, glass, automotive products, minerals, pharmaceuticals, plastics, metals, electronic equipment, furniture and a variety of food and tobacco products.

SCPC is engaged in the purchase, transmission and sale of natural gas on a wholesale basis to distribution companies (including SCE&G) and industrial customers throughout most of South Carolina. SCPC owns LNG liquefaction and storage facilities. It also supplies the natural gas for SCE&G's gas distribution system. Other resale customers include municipalities and county gas authorities and gas utilities. The industrial customers of SCPC are primarily engaged in the manufacturing or processing of ceramics, paper, metal, food and textiles.

SCG Pipeline provides interstate transportation services for natural gas to southeastern Georgia and South Carolina. SCG Pipeline transports natural gas from interconnections with Southern Natural at Port Wentworth, Georgia, and from an import terminal owned by Southern LNG, Inc. at Elba Island, near Savannah, Georgia. The endpoint of the pipeline is at the site of SCE&G's Jasper County Electric Generating Station. In 2005, SCANA expects to merge SCPC with SCG Pipeline, subject to customary closing conditions and FERC approval.

Nonregulated Businesses

SEMI markets natural gas primarily in the southeast and provides energy-related risk management services to producers and customers. In addition, SCANA Energy, a division of SEMI, markets natural gas to over 470,000 customers (as of December 31, 2004) in Georgia's natural gas market. The GPSC regulates the gas rates charged to approximately 60,000 of these customers who are served by SCANA Energy as the regulated provider. This group includes low-income and high credit risk customers. In March 2004 SCANA Energy acquired approximately 47,000 retail natural gas customers formerly served by another gas marketer in Georgia. With this transaction, SCANA Energy's total customer base represents about a 30 percent share of the approximately 1.5 million customers in Georgia's deregulated natural gas market. SCANA Energy remains the second largest natural gas marketer in the state.

SCI owns and operates a 500-mile fiber optic telecommunications network and data center facilities in South Carolina and, through its joint venture with FRC, LLC, has an interest in an additional 693 miles of fiber in South Carolina, North Carolina and Georgia. SCI also provides ethernet services in South Carolina, as well as tower site construction, management and rental services in South Carolina and North Carolina. SCH, a Delaware corporation and a wholly owned subsidiary of SCI, holds an insignificant investment in a telecommunications services company. In 2004 SCH sold its primary investments and recorded losses on those sales totaling $13.9 million, net of taxes. Also in 2004, SCH recorded impairment losses on its investments totaling $16.2 million, net of taxes. See additional discussion at the Liquidity and Capital Resources section of Management's Discussion and Analysis of Financial Condition and Results of Operations for SCANA.

Other significant businesses owned by SCANA are described in the preceding Corporate Structure section.

COMPETITION

For a discussion of the impact of competition, see the Overview section of Management's Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G, and the Competition section of Management's Narrative Analysis of Results of Operations for PSNC Energy.

CAPITAL REQUIREMENTS

SCANA's, SCE&G's and PSNC Energy's cash requirements arise primarily from operational needs, construction programs and payment of dividends. The ability of regulated utilities to replace existing plant investment, as well as to expand to meet future demand for electricity and gas, depends upon their ability to attract the necessary financial capital on reasonable terms. Regulated utilities recover the costs of providing services through rates charged to customers. Rates for regulated services are generally based on historical costs. As customer growth and inflation occur and the regulated utilities continue their ongoing construction programs, regulated utilities expect to seek increases in rates. SCANA's, SCE&G's and PSNC Energy's future financial position and results of operations will be affected by their ability to obtain adequate and timely rate and other regulatory relief, if requested.

For a discussion of the impact of various rate matters on capital requirements, see the Regulatory Matters section of Management's Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G and Note 2 to the consolidated financial statements for SCANA, SCE&G and PSNC Energy.

During the three-year period 2005-2007, SCANA, SCE&G and PSNC Energy expect to meet capital requirements principally through internally generated funds and the incurrence of additional short-term and long-term indebtedness and sales of additional equity securities by SCANA. Beginning in May 2004, shares of SCANA's common stock purchased on behalf of participants in the Investor Plus Plan and the Stock Purchase-Savings Plan were purchased directly from SCANA rather than on the open market. SCANA expects such purchases to continue indefinitely. SCANA, SCE&G and PSNC Energy expect that they have or can obtain adequate sources of financing to meet their projected cash requirements for the next 12 months and for the foreseeable future.

For a discussion of cash requirements for construction and nuclear fuel expenditures, see the Liquidity and Capital Resources section of Management's Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G.

CAPITAL PROJECTS

In May 2004 SCE&G's 880 megawatt Jasper County Electric Generating Station began commercial operation. The plant includes three natural gas combustion-turbine generators and one steam-turbine generator. The total cost of the project was approximately $506 million, which includes the original construction costs for the plant itself, as well as AFC and other project-related costs. All such costs have been approved for recovery in rate base.

In 2001 SCE&G began construction to reinforce its Lake Murray Dam in order to comply with new federal safety standards mandated by the FERC. Construction for the project and related activities is expected to cost approximately $275 million (excluding AFC) and be completed in 2005. Costs incurred through December 31, 2004 totaled approximately $240 million.

Construction of SCPC's South System Loop was completed in March 2004 at a cost of approximately $21 million. This pipeline stretches 38.3 miles from SCG Pipeline's connection with SCE&G's Jasper County Electric Generating Station to Yemassee in Hampton County, South Carolina, providing a new gas supply source to SCPC's current system.

For a discussion of contractual cash obligations, financing limits, financing transactions and other related information, see the Liquidity and Capital Resources section of Management's Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G and the Capital Expansion Program and Liquidity Matters section of Management's Narrative Analysis of Results of Operations for PSNC Energy.

SCANA's ratios of earnings to fixed charges were 2.65, 2.82, 0.53, 4.37 and 2.47 for the years ended December 31, 2004, 2003, 2002, 2001 and 2000, respectively. To achieve a ratio of 1.0 for the year ended December 31, 2002, SCANA would have needed an additional $108.6 million in income before income taxes. SCANA's ratio for 2002 was negatively impacted by the impairment charge related to the acquisition adjustment associated with PSNC Energy and the impairments of SCANA's investments in certain telecommunications securities. For SCE&G these ratios were 4.31, 4.13, 4.28, 4.54 and 5.02 for the same periods. For PSNC Energy these ratios were 2.80, 3.37, (7.78), 2.54 and 3.05 for the same periods. To achieve a ratio of 1.0 for the year ended December 31, 2002, PSNC Energy would have needed an additional $193.2 million in income before income taxes. PSNC Energy's ratio for 2002 was negatively impacted by the impairment charge related to the acquisition adjustment described above.

ELECTRIC OPERATIONS

Electric Sales

SCE&G's sales of electricity by class as a percent of total electric revenues for 2004 and 2003 were as follows:

CLASSIFICATION	2003	2004
Residential	42%	40%
Commercial	32%	30%
Industrial	19%	17%
Sales for resale	4%	9%
Other	2%	2%
Total Territorial	99%	98%
NMST	1%	2%
Total	100%	100%

Sales for resale include sales to one municipality and two electric cooperatives. Sales under the NMST during 2004 include sales to 31 investor-owned utilities and registered marketers, seven electric cooperatives, one municipality and three federal/state electric agencies. During 2003 sales under the NMST included sales to 29 investor-owned utilities and registered marketers, seven electric cooperatives, five municipalities and three federal/state electric agencies.

During 2004 SCE&G recorded a net increase of 14,324 customers, increasing its total electric customers to 585,264 at year end. A new all-time peak summer demand of 4,574 MW was set on July 14, 2004. The previous all-time peak demand of 4,474 MW was set on January 24, 2003.

For the three-year period 2005-2007, SCE&G's total territorial KWh sales of electricity are projected to increase 2.0% annually, assuming normal weather. SCE&G's total electric customer base is projected to increase 2.0% annually. Over the same three-year period, SCE&G's territorial peak load (summer, in MW) is projected to increase 2.2% annually. SCE&G's goal is to maintain a reserve margin of between 12% and 18%. As of December 31, 2004 the reserve margin was approximately 15%.

Electric Interconnections

SCE&G purchases all of the electric generation of GENCO's Williams Station under a Unit Power Sales Agreement which has been approved by FERC. See Properties—Electric Properties for Williams Station's generating capacity.

SCE&G's transmission system is part of the interconnected grid extending over a large part of the southern and eastern portions of the nation. SCE&G, Virginia Electric and Power Company, Duke Power Company, Carolina Power & Light Company (Progress Energy Carolinas), APGI (Yadkin Division) and Santee Cooper are members of the Virginia-Carolinas Reliability Group, one of several geographic divisions within the Southeastern Electric Reliability Council. This Council provides for coordinated planning for reliability among bulk power systems in the Southeast. SCE&G is also interconnected with Georgia Power Company, Savannah Electric and Power Company, Oglethorpe Power Corporation and the Southeastern Power Administration's Clarks Hill Project. For a discussion of the impact certain legislative and regulatory initiatives may have on SCE&G's transmission system, see Electric Operations within the Overview section of Management's Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G.

Fuel Costs

The following table sets forth the average cost of nuclear fuel, coal and gas and the weighted average cost of all fuels (including oil) for the years 2002-2004.

	Cost of Fuel Used		
	2002	**2003**	**2004**
Per MMBTU:			
Nuclear	$ .50	$ .53	$ .50
Coal—SCE&G	1.65	1.68	1.92
Coal—GENCO	1.70	1.75	2.12
Gas—SCE&G	3.11	7.02	7.31
All Fuels (weighted average)	1.48	1.58	1.96
Per Ton:			
Coal—SCE&G	$41.39	$42.06	$47.49
Coal—GENCO	43.30	44.30	52.69
Per MCF:			
Gas—SCE&G	$ 3.27	$ 7.76	$ 7.81

Fuel Supply

The following table shows the sources and approximate percentages of total MWh generation by each category of fuel for the years 2002-2004 and the estimates for the years 2005-2007.

	% of Total MWh Generated					
	Actual			Estimated		
	2002	**2003**	**2004**	**2005**	**2006**	**2007**
Coal	70%	70%	68%	67%	65%	65%
Nuclear	21	21	21	19	19	20
Hydro	4	6	4	5	5	5
Natural Gas & Oil	5	3	7	9	11	10
	100%	100%	100%	100%	100%	100%

Coal is used at five of SCE&G's fossil fuel-fired plants and GENCO's Williams Station. Unit train deliveries are used at all of these plants and in some cases truck deliveries are used. On December 31, 2004 SCE&G had approximately a 27-day supply of coal in inventory and GENCO had approximately a 22-day supply.

Coal is obtained through supply contracts and purchases on the spot market. Spot market purchases are expected to continue for coal requirements in excess of those provided by existing contracts or when spot market prices are favorable.

Contract coal is purchased from ten suppliers located in eastern Kentucky, Tennessee, West Virginia and southwest Virginia. Contract commitments, which expire at various times through 2008, are approximately 6 million tons annually, which is 86% of total expected coal purchases for 2005. Sulfur restrictions on the contract coal range from 1.0% to 1.5%.

SCANA & SCE&G believe that SCE&G's and GENCO's operations comply with all existing regulations relating to the discharge of sulfur dioxide and nitrogen oxides (NOx). See additional discussion at Environmental Matters in Management's Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G.

SCE&G has adequate supplies of uranium or enriched uranium product under contract to manufacture nuclear fuel for Summer Station through 2008. The following table summarizes all contract commitments for the stages of nuclear fuel assemblies:

Commitment	Contractor	Remaining Regions(1)	Expiration Date
Enrichment	United States Enrichment Corporation(2)	18-20	2008
Fabrication......	Westinghouse Electric Corporation	18-22	2011

(1) A region represents approximately one-third to one-half of the nuclear core in the reactor at any one time. Region 17 was loaded in 2003. Region 18 is scheduled to be loaded in 2005.

(2) Contract provisions for the delivery of enriched uranium product encompass supply, conversion and enrichment services.

SCE&G has on-site spent nuclear fuel storage capability until at least 2018 and expects to be able to expand its storage capacity to accommodate the spent fuel output for the life of Summer Station (including the license extension discussed below) through dry cask storage or other technology as it becomes available. In addition, there is sufficient on-site storage capacity over the life of Summer Station to permit storage of the entire reactor core in the event that complete unloading should become desirable or necessary. For information regarding the contract and pending litigation with the DOE for disposal of spent fuel, see Nuclear Fuel Disposal within the Environmental Matters section of Management's Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G.

Decommissioning

In April 2004 the NRC approved SCE&G's application for a 20-year license extension for Summer Station. The extension allows the plant to operate through August 6, 2042. For information regarding the decommissioning of Summer Station, see Note 1H, Nuclear Decommissioning, of SCANA's and SCE&G's consolidated financial statements.

GAS OPERATIONS

Gas Sales—Regulated

Sales of natural gas by class as a percent of total regulated gas revenues for 2004 and 2003 were as follows:

CLASSIFICATION	SCANA 2003	SCANA 2004	SCE&G 2003	SCE&G 2004	PSNC Energy 2003	PSNC Energy 2004
Residential	41.0%	40.8%	40.5%	38.8%	58.8%	59.3%
Commercial	24.1%	24.7%	32.4%	32.3%	28.3%	28.9%
Industrial	27.7%	29.3%	26.2%	28.1%	7.5%	6.5%
Sales for Resale	4.1%	1.5%	—	—	—	—
Transportation Gas	3.1%	3.7%	0.9%	0.8%	5.4%	5.3%
Total	100%	100%	100%	100%	100%	100%

For the three-year period 2005-2007, SCANA's total consolidated sales of regulated natural gas in DTs are projected to increase 1.6% annually, assuming normal weather. Residential DT sales are projected to increase 2.0% annually, commercial sales 2.0% and industrial sales 1.2%. Sales for resale are not expected to increase significantly. SCANA's total consolidated natural gas customer base is projected to increase 2.3% annually.

During 2004 SCANA recorded a net increase of approximately 20,300 regulated gas customers, increasing its regulated gas customers to approximately 691,000. SCE&G recorded a net increase of approximately 5,900 gas customers, increasing its total gas customers to approximately 282,000. PSNC Energy recorded a net increase of approximately 14,400 customers, increasing its total customers to approximately 408,000.

The demand for gas is affected principally by the weather and the price relationship between gas and alternate fuels.

SCPC, operating wholly within South Carolina, provides natural gas utility and transportation services for its industrial customers, and supplies natural gas to SCE&G and other wholesale purchasers. SCG Pipeline transports gas to SCE&G's Jasper County Electric Generating Station. In 2005, SCANA expects to merge SCPC and SCG Pipeline. See the Overview Section of SCANA's Management Discussion and Analysis of Financial Condition and Results of Operations.

Gas Cost, Supply and Curtailment Plans

South Carolina

SCPC purchases natural gas under contracts with producers and marketers in both the spot and long-term markets. The gas is brought to South Carolina through transportation agreements with Southern Natural (expiring in 2010) and Transco (expiring in 2008 and 2017). The daily volume of gas that SCPC is entitled to transport under these contracts on a firm basis is 188 MMCF from Southern Natural and 105 MMCF from Transco. Of these amounts, 3.5 MMCF from Southern Natural and 1.9 MMCF from Transco have been temporarily released to the City of Orangeburg for a period of two years, and 22.3 MMCF from Southern Natural and 12.5 MMCF from Transco have been temporarily released to Patriots Energy Group for a period of two years. SCPC also had an additional firm service contract with Southern Natural (expiring in 2017) for 50 MMCF which was temporarily assigned to SCE&G for use in electric generation. In February 2005, the Southern Natural contract was permanently assigned to SCE&G. Additional natural gas volumes are brought to SCPC's system as capacity is available for interruptible transportation. SCE&G, under contract with SCPC, is entitled to receive a daily contract demand of 276,495 DTs for resale to SCE&G's customers. The contract allows

SCE&G to receive amounts in excess of this demand based on availability. In addition, SCE&G, under contract with SEMI, is entitled to receive a daily contract demand of 120,000 DTs for use in electric generation. SCG transports the gas to SCE&G under a separate contract.

During 2004 SCPC's average cost per MCF of natural gas purchased for resale, including firm service demand charges, was $6.99, compared to $6.18 during 2003. SCE&G's average cost per MCF was $7.96 and $6.82 during 2004 and 2003, respectively.

SCPC's tariffs include a purchased gas adjustment (PGA) clause that provides for the recovery of actual gas costs incurred. The SCPSC has ruled that the results of SCPC's hedging activities are to be included in the PGA. As such, costs of related derivatives that SCPC utilizes to hedge its gas purchasing activities are recoverable through its weighted average cost of gas calculation. The offset to the change in fair value of these derivatives is recorded as a current asset or liability.

To meet the requirements of its high priority natural gas customers during periods of maximum demand, SCPC supplements its supplies of natural gas from two LNG liquefaction and storage facilities. The LNG plants are capable of storing the liquefied equivalent of 1,880 MMCF of natural gas. Approximately 1,732 MMCF (liquefied equivalent) of gas were in storage at December 31, 2004. On peak days the LNG plants can regasify up to 150 MMCF per day. Additionally, SCPC had contracted for 6,447 MMCF of natural gas storage space, of which, 154 MMCF has been temporarily released to Patriots Energy Group for a period of two years. Approximately 5,104 MMCF of gas were in storage on December 31, 2004.

The SCPSC has established allocation priorities applicable to the firm and interruptible capacities of SCPC. These curtailment plan priorities apply to SCPC's direct industrial customers and resale distribution customers, including SCE&G.

North Carolina

PSNC Energy purchases natural gas under contracts with producers and marketers on a short-term basis at current price indices and on a long-term basis for reliability assurance at index prices plus a reservation charge. The gas is brought to North Carolina through transportation agreements with Transco and Dominion Transmission, Inc. with expiration dates ranging through 2016. The daily volume of gas that PSNC Energy is entitled to transport under these contracts on a firm basis is 259,894 DT from Transco and 30,331 DT from Dominion Transmission. In addition, PSNC Energy is entitled to firm transportation service on the Patriot Extension Project, a project of East Tennessee Natural Gas Company, and firm storage service on the Saltville Storage Project, an affiliate of East Tennessee Natural Gas Company, that provide an aggregate daily demand of 30,000 DT.

During 2004 PSNC Energy's average cost per DT of natural gas purchased for resale, including firm service demand charges, was $7.95, compared to $6.80 during 2003.

To meet the requirements of its high priority natural gas customers during periods of maximum demand, PSNC Energy supplements its supplies of natural gas with underground natural gas storage services and LNG peaking services. Underground natural gas storage service agreements with Dominion Gas Transmission, Columbia Gas Transmission, Transco and East Tennessee Natural Gas Company provide for storage capacity of approximately 12,000 MMCF. Approximately 9,900 MMCF were in storage at December 31, 2004. In addition, PSNC Energy's own LNG facility is capable of storing the liquefied equivalent of 1,000 MMCF of natural gas with regasification capability of approximately 100 MMCF per day. Approximately 520 MMCF (liquefied equivalent) were in storage at December 31, 2004. LNG storage service agreements with Transco, Cove Point LNG and Pine Needle LNG provide for 1,300 MMCF (liquefied equivalent) of storage space. Approximately 1,110 MMCF (liquefied equivalent) were in storage at December 31, 2004.

SCANA, SCE&G and PSNC Energy believe that supplies under long-term contracts and supplies available for spot market purchase are adequate to meet existing customer demands and to accommodate growth.

Gas Marketing—Nonregulated

SEMI's activities are primarily focused in the Southeast, where SEMI markets natural gas and provides energy-related risk management services to producers and consumers. In addition, SCANA Energy, a division of SEMI, markets natural gas to over 470,000 customers (as of December 31, 2004) in Georgia's natural gas market. In March 2004 SCANA Energy acquired approximately 47,000 retail natural gas customers formerly served by another gas marketer in Georgia. With this transaction, SCANA Energy's total customer base represents about a 30 percent share of the approximately 1.5 million customers in Georgia's deregulated natural gas market. SCANA Energy remains the second largest natural gas marketer in the state.

Policies and procedures and risk limits are established to control the level of market, credit, liquidity and operational and administrative risks assumed by SCANA, SCE&G and PSNC Energy. The Board of Directors of each company has delegated to a Risk Management Committee the authority to set risk limits, establish policies and procedures for risk management and measurement, and to oversee and review the risk management process and infrastructure. The Risk Management Committee, which is comprised of certain officers, including a Risk Management Officer and senior officers, apprises the Board of Directors with regard to the management of risk and brings to the Board's attention any areas of concern. Written policies define the physical and financial transactions that are approved, as well as the authorization requirements and limits for transactions.

REGULATION

SCANA is a registered public utility holding company under PUHCA. SCANA and its subsidiaries are subject to the jurisdiction of the SEC as to financings, acquisitions and diversifications, affiliate transactions and other matters. Certain subsidiaries of SCANA are regulated by state public service commissions or FERC as to the following matters.

SCE&G is subject to the jurisdiction of the SCPSC as to retail electric and gas rates, service, accounting, issuance of securities (other than short-term borrowings) and other matters.

GENCO is subject to the jurisdiction of the SCPSC as to issuance of securities (other than short-term borrowings) and is subject to the jurisdiction of FERC as to accounting and other matters.

PSNC Energy is subject to the jurisdiction of the NCUC as to gas rates, service, issuance of securities (other than notes with a maturity of two years or less or renewals of notes with a maturity of six years or less), accounting and other matters.

SCPC is subject to the jurisdiction of the SCPSC as to gas rates, service, accounting and other matters.

SCG Pipeline is subject to the jurisdiction of FERC as to gas rates, service, accounting and other matters.

SCANA Energy is regulated by the GPSC through its certification as a natural gas marketer in Georgia and specifically is subject to the jurisdiction of the GPSC as to gas rates for certain of its customers classified as low-income or high credit risk and as to certain other marketing activities.

SCE&G and GENCO are subject to regulation under the Federal Power Act, administered by FERC and DOE, in the transmission of electric energy in interstate commerce and in the sale of electric energy at wholesale for resale, as well as with respect to licensed hydroelectric projects and certain other matters, including accounting. See the Regulatory Matters section of Management's Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G.

SCE&G holds licenses under the Federal Water Power Act or the Federal Power Act with respect to all of its hydroelectric projects. The expiration dates of the licenses covering the projects are as follows:

Project	License Expiration	Project	License Expiration
Saluda (Lake Murray)	2010	Stevens Creek	2025
Fairfield Pumped Storage . . .	2020	Neal Shoals	2036
Parr Shoals	2020		

In November 2003 FERC granted SCE&G a five-year license extension (until 2010) for the Saluda project at Lake Murray because the FERC-mandated draw-down of Lake Murray will affect the studies required of normal lake conditions. The five-year extension will allow time for the lake level to return to normal operating conditions and to stabilize in order to conduct meaningful studies that may impact future license requirements. For a discussion of SCE&G's agreement with FERC to reinforce the Lake Murray Dam (related to the Saluda project), see the previous discussion under Capital Projects and see Liquidity and Capital Resources in Management's Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G.

At the termination of a license under the Federal Power Act, the United States government may take over the project covered thereby, or FERC may extend the license or issue a license to another applicant. If the federal government takes over a project or FERC issues a license to another applicant, the original licensee is entitled to be paid its net investment in the project, not to exceed fair value, plus severance damages.

For a discussion of legislative and regulatory initiatives being proposed that would affect SCE&G's transmission system, see Electric Operations within the Overview section of Management's Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G.

SCE&G is subject to regulation by the NRC with respect to the ownership, operation and decommissioning of Summer Station. The NRC's jurisdiction encompasses broad supervisory and regulatory powers over the construction and operation of nuclear reactors, including matters of health and safety, antitrust considerations and environmental impact. In addition, the Federal Emergency Management Agency is responsible for the review, in conjunction with the NRC, of certain aspects of emergency planning relating to the operation of nuclear plants.

RATE MATTERS

For a discussion of the impact of various rate matters, see the Regulatory Matters section of Management's Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G, and Note 2 to the consolidated financial statements for SCANA, SCE&G and PSNC Energy.

SCE&G's and PSNC Energy's gas rate schedules for their residential and small commercial and small industrial customers include a WNA. SCE&G's and PSNC Energy's WNA were approved by the SCPSC and NCUC, respectively, and are in effect for bills rendered during the period November 1 through April 30 of each year. In each case the WNA increases tariff rates if weather is warmer than normal and decreases rates if weather is colder than normal. The WNA does not change the seasonality of gas revenues; however, it does reduce fluctuations caused by abnormal weather.

In a January 2005 order the SCPSC granted SCE&G a composite increase in retail electric rates of approximately 2.89%, designed to produce additional annual revenues of approximately $41.4 million based on a test year calculation. The SCPSC lowered SCE&G's return on common equity from 12.45% to a range of between 10.4% and 11.4%, with rates to be set at 10.7%. The new rates became effective in January 2005. As part of its order, the SCPSC approved SCE&G's recovery of construction and operating costs for SCE&G's new Jasper County Electric Generating Station, recovery of costs of mandatory environmental upgrades primarily related to Federal Clean Air Act regulations and the application of current and anticipated net synthetic fuel tax credits to offset the cost of constructing the back-up dam at Lake Murray. The SCPSC also approved recovery over a five-year period of SCE&G's approximately $14 million of costs incurred in the formation of the GridSouth Regional Transmission Organization and recovery through base rates over three years of approximately $25.6 million of purchased power costs that were previously deferred. As a part of its order, the SCPSC extended through 2010 its approval of the accelerated capital recovery plan for SCE&G's Cope Generating Station. Under the plan, based on the level of revenues and operating expenses, SCE&G may increase depreciation of its Cope Generating Station in excess of amounts that would be recorded based upon currently approved depreciation rates, not to exceed $36 million annually, without additional approval of the SCPSC. Any unused portion of the $36 million in any given year may be carried forward for possible use in the following year.

Fuel Cost Recovery Procedures

The SCPSC has established a fuel cost recovery procedure which determines the fuel component in SCE&G's retail electric base rates annually based on projected fuel costs for the ensuing 12-month period, adjusted for any overcollection or undercollection from the preceding 12-month period. SCE&G has the right to request a formal proceeding at any time should circumstances dictate such a review. In April 2004 the SCPSC approved SCE&G's request to increase the fuel component of rates charged to electric customers from 1.678 cents per KWh to 1.821 cents per KWh. The increase reflects higher fuel costs projected for the period May 2004 through April 2005. The increase also provides continued recovery for under-collected actual fuel costs through February 2004. The new rates were effective as of the first billing cycle in May 2004.

SCE&G's gas rate schedules and contracts include mechanisms that allow it to recover from its customers changes in the actual cost of gas. SCE&G's firm gas rates allow for the recovery of the cost of gas, based on projections, as established by the SCPSC in annual gas cost and gas purchase practice hearings. Any differences between actual and projected gas costs are deferred and included when projecting gas costs during the next annual gas cost recovery hearing.

PSNC Energy operates under two rate provisions in addition to WNA that serve to reduce fluctuations in PSNC Energy's earnings. First, its Rider D rate mechanism allows PSNC Energy to recover, in any manner authorized by the NCUC, margin losses on negotiated gas sales. The Rider D rate mechanism also allows PSNC Energy to recover from customers all prudently incurred gas costs, including changes in natural gas prices. Second, PSNC Energy operates with full margin transportation rates. These rates allow PSNC Energy to earn the same margin on gas delivered to customers regardless of whether the gas is sold or only transported by PSNC Energy to the customer.

PSNC Energy's rates are established using a benchmark cost of gas approved by the NCUC, which may be modified periodically to reflect changes in the market price of natural gas. PSNC Energy revises its tariffs with the NCUC as necessary to track these changes and accounts for any over- or under-collections of the delivered cost of gas in its deferred accounts for subsequent rate consideration. The NCUC reviews PSNC Energy's gas purchasing practices annually.

SCPC's purchased gas adjustment for cost recovery and gas purchasing policies are reviewed annually by the SCPSC. In an October 2004 order, the SCPSC found that for the period January 2003 through December 2003 SCPC's gas purchasing policies and practices were prudent and SCPC properly adhered to the gas cost recovery provisions of its gas tariff.

ENVIRONMENTAL MATTERS

Federal and state authorities have imposed environmental regulations and standards relating primarily to air emissions, wastewater discharges and solid, toxic and hazardous waste management. Developments in these areas may require that equipment and facilities be modified, supplemented or replaced. The ultimate effect of these regulations and standards upon existing and proposed operations cannot be predicted. For a more complete discussion of how these regulations and standards impact SCANA, SCE&G and PSNC Energy, see the Environmental Matters section of Management's Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G and the consolidated financial statements for SCANA and SCE&G (Note 10C) and PSNC Energy (Note 8A).

OTHER MATTERS

For a discussion of SCE&G's insurance coverage for Summer Station, see Note 10B to the consolidated financial statements for SCANA and for SCE&G.

ITEM 2. PROPERTIES

SCANA owns no significant property other than the capital stock of each of its subsidiaries. It holds, directly or indirectly, all of the capital stock of each of its subsidiaries except for the preferred stock of SCE&G. It also has an investment in one LLC which operates a cogeneration facility in Charleston, South Carolina.

SCE&G's bond indentures, securing the First and Refunding Mortgage Bonds and First Mortgage Bonds issued thereunder, constitute direct mortgage liens on substantially all of its property. GENCO's Williams Station is also subject to a first mortgage lien.

For a brief description of the properties of SCANA's other subsidiaries, which are not significant as defined in Rule 1-02 of Regulation S-X, see Item 1, BUSINESS—SEGMENTS OF BUSINESS—Nonregulated Businesses.

ELECTRIC PROPERTIES

Information on electric generating facilities, all of which are owned by SCE&G except as noted, is as follows:

Facility	Present Fuel Capability	Location	Year In-Service	Net Generating Capacity (Summer Rating) (MW)
Steam Turbines				
Summer(1)	Nuclear	Parr, SC	1984	644
McMeekin	Coal/Gas	Irmo, SC	1958	250
Canadys	Coal/Gas	Canadys, SC	1962	396
Wateree	Coal	Eastover, SC	1970	700
Williams(2)	Coal	Goose Creek, SC	1973	615
D-Area(3)	Coal	DOE Savannah River Site, SC	1995	35
Cope	Coal	Cope, SC	1996	410
Cogen South(4)		Charleston, SC	1999	90
Combined Cycle				
Urquhart(5)	Coal/Gas/Oil	Beech Island, SC	1953/2002	568
Jasper	Gas/Oil	Hardeeville, SC	2004	880
Hydro(6)				
Saluda (Lake Murray)		Irmo, SC	1930	206
Pumped Storage				
Fairfield		Parr, SC	1978	576

(1) Represents SCE&G's two-thirds portion of the Summer Station (one-third owned by Santee Cooper).

(2) The steam unit at Williams Station is owned by GENCO.

(3) This plant is leased from the DOE and is dedicated to DOE's Savannah River Site steam needs. The reported net generating capacity for this plant is its expected average hourly output. The lease expires on October 1, 2005.

(4) SCE&G receives shaft horse power from Cogen South, LLC to operate SCE&G's generator. Cogen South, LLC is owned 50% by SCANA and 50% by MeadWestvaco.

(5) Two combined-cycle turbines burn natural gas or fuel oil to produce 341 MW of electric generation and use exhaust heat to replace coal-fired steam that powers two 75 MW turbines at the Urquhart Generating Station. Unit 3 remains as the only coal-fired steam unit at the site.

(6) SCE&G also owns three other hydro units in South Carolina that were placed in service in 1905 and 1914 and have an aggregate net generating capacity of 32 MW.

SCE&G owns nine other combustion turbine peaking units fueled by gas and/or oil located at various sites in SCE&G's service territory. These turbines were placed in service at various times from 1961 to 1999 and have aggregate net generating capacity of 365 MW.

SCE&G owns 439 substations having an aggregate transformer capacity of 25.6 million KVA (kilovolt-ampere). The transmission system consists of 3,255 miles of lines, and the distribution system consists of 17,621 pole miles of overhead lines and 4,903 trench miles of underground lines.

NATURAL GAS DISTRIBUTION AND TRANSMISSION PROPERTIES

SCE&G's natural gas system consists of approximately 13,700 miles of distribution mains and related service facilities. SCE&G also has propane air peak shaving facilities which can supplement the supply of natural gas by gasifying propane to yield the equivalent of 70 MMCF per day. These facilities can store the equivalent of 244 MMCF of natural gas.

SCPC's natural gas system consists of approximately 1,820 miles of transmission pipeline of up to 24 inches in diameter which connect its resale customers' distribution systems with transmission systems of Southern Natural and Transco. SCPC owns two LNG plants, one located near Charleston, South Carolina and the other in Salley, South Carolina. The Charleston facility can liquefy up to 6 MMCF per day and store the liquefied equivalent of 980 MMCF of natural gas. The Salley facility can store the liquefied equivalent of 900 MMCF of natural gas and has no liquefying capabilities. On peak days, the Charleston facility can regasify up to 60 MMCF per day and the Salley facility can regasify up to 90 MMCF.

PSNC Energy's natural gas system consists of approximately 870 miles of transmission pipeline of up to 24 inches in diameter that connect its distribution systems with Transco. PSNC Energy's distribution system consists of approximately 8,180 miles of distribution mains and related service facilities. PSNC Energy owns one LNG plant with storage capacity of 1,000 MMCF and the capacity to regasify approximately 100 MMCF per day. PSNC Energy also owns, through a wholly owned subsidiary, 33.21% of Cardinal Pipeline Company, LLC, which owns a 105-mile transmission pipeline in North Carolina. In addition, PSNC Energy owns, through a wholly owned subsidiary, 17% of Pine Needle LNG Company, LLC. Pine Needle owns and operates a liquefaction, storage and regasification facility in North Carolina.

ITEM 3. LEGAL PROCEEDINGS

Certain material legal proceedings and environmental and regulatory matters and uncertainties, some of which remain outstanding at December 31, 2004, are described below. These issues affect SCANA and, to the extent indicated, they also affect SCE&G or PSNC Energy.

Rate and Other Regulatory Matters

In a January 2005 order the SCPSC granted SCE&G a composite increase in retail electric rates of approximately 2.89%, designed to produce additional annual revenues of approximately $41.4 million based on a test year calculation. The SCPSC lowered SCE&G's return on common equity from 12.45% to a range of between 10.4% and 11.4%, with rates to be set at 10.7%. The new rates became effective in January 2005. As part of its order, the SCPSC approved SCE&G's recovery of construction and operating costs for SCE&G's new Jasper County Electric Generating Station, recovery of costs of mandatory environmental upgrades primarily related to Federal Clean Air Act regulations and the application of current and anticipated net synthetic fuel tax credits to offset the cost of constructing the back-up dam at Lake Murray. The SCPSC also approved recovery over a five-year period of SCE&G's approximately $14 million of costs incurred in the formation of the GridSouth Regional Transmission Organization and recovery through base rates over three years of approximately $25.6 million of purchased power costs that were previously deferred. As a part of its order, the SCPSC extended through 2010 its approval of the accelerated capital recovery plan for SCE&G's Cope Generating Station. Under the plan, based on the level of revenues and operating expenses, SCE&G may increase depreciation of its Cope Generating Station in excess of amounts that would be recorded based upon currently approved depreciation rates, not to exceed $36 million annually, without additional approval of the SCPSC. Any unused portion of the $36 million in any given year may be carried forward for possible use in the following year.

In 2001 SCE&G began construction to reinforce its Lake Murray Dam in order to comply with new federal safety standards mandated by the FERC. Construction for the project and related activities is expected to cost approximately $275 million (excluding AFC) and be completed in 2005. Costs incurred through December 31, 2004 totaled approximately $240 million.

Environmental Matters

SCE&G owns a decommissioned MGP site in the Calhoun Park area of Charleston, South Carolina. The site is currently being remediated for contamination. SCE&G anticipates that the remaining remediation activities will be completed by the end of 2005, with certain monitoring and other activities continuing until 2010. As of December 31, 2004, SCE&G has spent approximately $20.5 million to remediate the Calhoun Park site, and expects to spend an additional $1.3 million. In addition, SCE&G is party to certain claims for cost and damages from this site, for which claims the National Park Service of the Department of the Interior made an initial demand for payment of approximately $9 million. Any costs arising from these matters are expected to be recoverable through rates under South Carolina regulatory processes.

SCE&G owns three other decommissioned MGP sites in South Carolina which contain residues of by-product chemicals. One of the sites has been remediated and will undergo routine monitoring until released by DHEC. The other two sites are currently being investigated under work plans approved by DHEC. SCE&G anticipates that major remediation activities for the three sites will be completed in 2010. As of December 31, 2004, SCE&G has spent approximately $4 million related to these three sites, and expects to spend an additional $4 million.

PSNC Energy is responsible for environmental cleanup at five sites in North Carolina on which MGP residuals are present or suspected. PSNC Energy's actual remediation costs for these sites will depend on a number of factors, such as actual site conditions, third-party claims and recoveries from other PRPs. PSNC Energy has recorded a liability and associated regulatory asset of approximately $6.5 million, which reflects the estimated remaining liability at December 31, 2004. Amounts incurred and deferred to date, net of insurance settlements, that are not currently being recovered through gas rates are approximately $1.4 million. Management believes that all MGP cleanup costs incurred will be recoverable through gas rates.

On January 28, 2004 SCE&G and Santee Cooper (one-third owner of Summer Station) filed suit in the Court of Federal Claims against the DOE for breach of contract. The contract, entered into in 1983, known as the Standard Contract for Disposal of Spent Nuclear Fuel and/or High-Level Radioactive Waste (Standard Contract) required the federal government to accept and dispose of spent nuclear fuel and high-level radioactive waste beginning not later than January 31, 1998, in exchange for agreed payments fixed in the Standard Contract at particular amounts. As of the date of filing, the federal government has accepted no spent fuel from Summer Station or any other utility for transport and disposal, and has indicated that it does not anticipate doing so until 2010, at the earliest. As a consequence of the federal government's breach of contract, the plaintiffs have incurred and will continue to incur substantial costs. There are two additional causes of action alleged as well—a claim for damages for breach of the implied covenant of good faith and fair dealing and a takings claim demanding just compensation for the taking of the plaintiffs' real property (necessitated by the storage). This lawsuit is similar to numerous other lawsuits brought by nuclear utilities.

Pending Litigation

In 1999 an unsuccessful bidder for the purchase of certain of SCANA's propane gas assets filed suit against SCANA in Circuit Court, seeking unspecified damages. The suit alleged the existence of a contract for the sale of assets to the plaintiff and various causes of action associated with that contract. On October 21, 2004, the jury issued an adverse verdict on this matter against SCANA for four causes of action for damages totaling $48 million. Post-verdict motions were heard in November 2004 and January 2005. It is SCANA's interpretation that the damages awarded with respect to certain causes of action are overlapping. Therefore, it is SCANA's belief that a reasonably possible estimate of the total damages based on the amounts awarded by the jury will be in the range of $18-$36 million. However, SCANA believes that the verdict was inconsistent with the facts presented and applicable law and intends to appeal any adverse judgment by the Circuit Court. Based on the current status of this matter, and in accordance with generally accepted accounting principles, SCANA recorded a pre-tax charge to earnings in the third quarter of 2004 of $18 million, $11 million after-tax, or 10 cents per share, which is SCANA's reasonable estimate of the minimum loss that is probable if the final judgment is consistent with the jury verdict. The charge and associated liability are reported in Other Income (Expense) and Current Liabilities-Other in the financial statements. It is expected that the final judgment will be rendered in 2005 but that appeals may continue for a longer period. The Company is also defending another claim for $2.7 million for reimbursement of legal fees and expenses under an indemnification and hold harmless agreement in the contract of sale. A bench trial on the indemnification was held on January 14, 2005, and a ruling is expected in March.

On August 21, 2003, SCE&G was served as a co-defendant in a purported class action lawsuit styled as Collins v. Duke Energy Corporation, Progress Energy Services Company, and SCE&G, in South Carolina's Circuit Court of Common Pleas for the Fifth Judicial Circuit. The plaintiffs are seeking damages for the alleged improper use of electric transmission and distribution easements but have not asserted a dollar amount for their claims. Specifically, the plaintiffs contend that the licensing of attachments on electric utility poles, towers and other facilities to non-utility third parties or telecommunication companies for other than the electric utilities' internal use along the electric transmission line right-of-way constitutes a trespass. SCANA is confident of the propriety of SCE&G's actions. SCE&G intends to mount a vigorous defense. SCANA and SCE&G further believe that the resolution of these claims will not have a material adverse impact on their results of operations, cash flows or financial condition.

On May 17, 2004, SCANA and SCE&G were served with a purported class action lawsuit styled as Douglas E. Gressette, individually and on behalf of other persons similarly situated, v. South Carolina Electric & Gas Company and SCANA Corporation. The case was filed in South Carolina's Circuit Court of Common Pleas for the Ninth Judicial Circuit. The plaintiff alleges SCANA and SCE&G made improper use of certain easements and rights-of-way by allowing fiber optic communication lines and/or wireless communication apparatuses to transmit communications other than SCANA's and SCE&G's electricity-related internal communications. The plaintiff asserts causes of action for unjust enrichment, trespass, injunction and declaratory judgment. The plaintiff did not assert a specific dollar amount for the claims. SCANA and SCE&G believe their actions are consistent with governing law and the applicable documents granting easements and rights-of-way. SCANA and SCE&G intend to mount a vigorous defense and believe that the resolution of these claims will not have a material adverse impact on their results of operations, cash flows or financial condition.

A complaint was filed on October 22, 2003 against SCE&G by the State of South Carolina alleging that SCE&G violated the Unfair Trade Practices Act by charging municipal franchise fees to some customers residing outside a municipality's limits. The complaint alleged that SCE&G failed to obey, observe or comply with the lawful order of the SCPSC by charging franchise fees to those not residing within a municipality. The complaint sought restitution to all affected customers and penalties of up to $5,000 for each separate violation. The State of South Carolina v. SCE&G has been settled by an agreement between the parties, and the settlement has been approved by the court. The allegations are also the subject of a purported class action lawsuit filed in December 2003, against Duke Energy Corporation, Progress Energy Services Company and SCE&G (styled Edwards v. SCE&G). Duke Energy and Progress Energy have been voluntarily dismissed from the Edwards lawsuit. SCANA and SCE&G believe that the resolution of these actions will not have a material adverse impact on their results of operations, cash flows or financial condition. In addition, SCE&G filed a petition with the SCPSC on October 23, 2003 pursuant to S. C. Code Ann. R.103-836. The petition requests that the SCPSC exercise its jurisdiction to investigate the operation of the municipal franchise fee collection requirements applicable to SCE&G's electric and gas service, to approve SCE&G's efforts to correct any past franchise fee billing errors, to adopt improvements in the system which will reduce such errors in the future, and to adopt any regulation that the SCPSC deems just and proper to regulate the franchise fee collection process.

SCANA, SCE&G and PSNC Energy are also engaged in various other claims and litigation incidental to their business operations which management anticipates will be resolved without material loss to any of them.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

Not Applicable.

EXECUTIVE OFFICERS OF SCANA CORPORATION

The executive officers are elected at the annual meeting of the Board of Directors, held immediately after the annual meeting of shareholders, and hold office until the next such annual meeting, unless a resignation is submitted, or unless the Board of Directors shall otherwise determine. Positions held are for SCANA and all subsidiaries unless otherwise indicated.

Name	Age	Positions Held During Past Five Years	Dates
William B. Timmerman	58	Chairman of the Board, President and Chief Executive Officer	*-present
Joseph C. Bouknight	51	Senior Vice President—Human Resources	2004-present
		Vice President Human Resources—Dan River, Inc.—Danville, VA	*-2004
George J. Bullwinkel	56	President and Chief Operating Officer—SEMI	2004-present
		President and Chief Operating Officer—ServiceCare	2002-present
		President and Chief Operating Officer—SCI	*-present
		President and Chief Operating Officer—SCPC and SCG Pipeline	2002-2004
		Senior Vice President—Governmental Affairs and Economic Development	*-2002
Sarena D. Burch	48	Senior Vice President—Fuel Procurement and Asset Management—SCE&G, PSNC Energy and SCPC	2003-present
		Deputy General Counsel and Assistant Secretary—SCANA Services	*-2003
Stephen A. Byrne	45	Senior Vice President—Generation, Nuclear and Fossil Hydro—SCE&G	2001-present
		Vice President—Nuclear Operations—SCE&G	*-2001
Paul V. Fant	51	Senior Vice President Transmission Services, President and Chief Operating Officer-South Carolina Pipeline Corporation and SCG Pipeline, Inc.	2004-present
		Executive Vice President-South Carolina Pipeline Corporation	*-2004
		Executive Vice President—SCG Pipeline, Inc.	2001-2004
Sharon K. Jenkins	47	Senior Vice President—Marketing and Communications	2003-present
		Vice President, Marketing—Wireless and Broadband Systems Division—Motorola, Inc.—Austin, TX	*-2003
Neville O. Lorick	54	President and Chief Operating Officer—SCE&G	*-present
Kevin B. Marsh	49	Senior Vice President and Chief Financial Officer	*-present
		President and Chief Operating Officer—PSNC Energy	2001-2003
Charles B. McFadden	60	Senior Vice President—Governmental Affairs and Economic Development—SCANA Services	2003-present
		Vice President—Governmental Affairs and Economic Development—SCANA Services	*-2003
Francis P. Mood, Jr.	66	Senior Vice President, General Counsel and Assistant Secretary	2005-present
		Attorney, Haynsworth Sinkler Boyd, P.A.—Columbia, SC	*-2005

* Indicates position held at least since March 1, 2000.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

COMMON STOCK INFORMATION

SCANA Corporation

	2004				2003			
	4th Qtr.	3rd Qtr.	2nd Qtr.	1st Qtr.	4th Qtr.	3rd Qtr.	2nd Qtr.	1st Qtr.
Price Range (New York Stock Exchange Composite Listing):								
High	$39.71	$38.09	$36.88	$36.29	$35.70	$35.23	$35.45	$32.70
Low	36.39	35.66	32.82	33.42	32.80	31.89	29.82	28.10

The principal market for SCANA common stock is the New York Stock Exchange, using the ticker symbol SCG. The corporate name SCANA is used in newspaper stock listings. At February 18, 2005 SCANA common stock totaling 112,909,904 shares were held by approximately 37,219 stockholders of record.

SCANA declared quarterly dividends on its common stock of $.365 per share and $.345 per share in 2004 and 2003, respectively.

SCE&G and PSNC Energy

All of SCE&G's and PSNC Energy's common stock is owned by SCANA and has no market. During 2004 and 2003 SCE&G paid $143.0 million and $149.3 million, respectively, in cash dividends to SCANA. During 2004 and 2003 PSNC Energy paid $14.5 million and $18.5 million, respectively, in cash distributions/dividends to SCANA.

SECURITIES RATINGS (As of February 18, 2005)

	SCANA(1)	SCE&G(1)				PSNC Energy(2)	
Rating Agency	Senior Unsecured	Senior Secured	Senior Unsecured	Preferred Stock	Commercial Paper	Senior Unsecured	Commercial Paper
Moody's	A3	A1	A2	Baa1	P-1	A2	P-1
Standard & Poors (S&P)	BBB+	A-	BBB+	BBB	A-2	A-	A-2
Fitch	A-	A+	A	A	F-1	NR	NR

(1) S&P and Fitch ratings carry a stable outlook. Moody's outlook is negative.

(2) Stable outlook

Additional information regarding these debt and equity securities is provided in Notes 4, 5 and 7 to the consolidated financial statements for SCANA and SCE&G and Notes 4 and 5 to the consolidated financial statements for PSNC Energy.

Securities ratings used by Moody's, Standard & Poors and Fitch are as follows:

Long-term (investment grade)			**Short-term**		
Moody's(3)	**S&P(4)**	**Fitch(4)**	**Moody's**	**S&P**	**Fitch**
Aaa	AAA	AAA	Prime-1 (P-1)	A-1	F-1
Aa	AA	AA	Prime-2 (P-2)	A-2	F-2
A	A	A	Prime-3 (P-3)	A-3	F-3
Baa	BBB	BBB	Not Prime	B	B
				C	C
				D	D

(3) Additional Modifiers: 1, 2, 3 (Aa to Baa)

(4) Additional Modifiers: +/- (AA to BBB)

A security rating should be evaluated independently of other ratings and is not a recommendation to buy, sell or hold securities. In addition, security ratings are subject to revision or withdrawal at any time by the assigning rating organization.

For a discussion of provisions that could limit the payment of cash dividends see Management's Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G and Note 6 to the consolidated financial statements for SCANA and SCE&G. For a summary of equity securities issuable under SCANA's compensation plans at December 31, 2004, see Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.

ITEM 6. SELECTED FINANCIAL AND OTHER STATISTICAL DATA

As of or for the Year Ended December 31,	SCANA 2004	SCANA 2003	SCANA 2002	SCANA 2001	SCANA 2000	SCE&G 2004	SCE&G 2003	SCE&G 2002	SCE&G 2001	SCE&G 2000
	(Millions of dollars, except statistics and per share amounts)									
Statement of Operation Data										
Operating Revenues	$ 3,885	$ 3,416	$ 2,954	$ 3,451	$ 3,433	$ 2,089	$ 1,832	$ 1,683	$ 1,715	$ 1,669
Operating Income	596	551	514	528	554	475	440	431	439	469
Other Income (Expense)	(7)	75	(180)	550	44	26	36	37	30	16
Income Before Cumulative Effect of Accounting Change	257	282	88	539	221	232	220	219	222	231
Net Income (Loss)(1)	257	282	(142)	539	250	232	220	219	222	253
Common Stock Data										
Weighted Average Number of Common Shares Outstanding (Millions)	111.6	110.8	106.0	104.7	104.5	n/a	n/a	n/a	n/a	n/a
Basic and Diluted Earnings (Loss) Per Share(1)	$ 2.30	$ 2.54	$ (1.34)	$ 5.15	$ 2.40	n/a	n/a	n/a	n/a	n/a
Dividends Declared Per Share of Common Stock	$ 1.46	$ 1.38	$ 1.30	$ 1.20	$ 1.15	n/a	n/a	n/a	n/a	n/a
Balance Sheet Data										
Utility Plant, Net	$ 6,762	$ 6,417	$ 5,474	$ 5,263	$ 4,949	$ 5,162	$ 5,293	$ 4,729	$ 4,065	$ 3,793
Total Assets	8,996	8,458	8,074	7,822	7,427	6,980	6,628	5,958	5,138	4,842
Capitalization:										
Common equity	$ 2,451	$ 2,306	$ 2,177	$ 2,194	$ 2,032	$ 2,164	$ 2,043	$ 1,966	$ 1,750	$ 1,657
Preferred Stock (Not subject to purchase or sinking funds)	106	106	106	106	106	106	106	106	106	106
Preferred Stock, net (Subject to purchase or sinking funds)	9	9	9	10	10	9	9	9	10	10
SCE&G—Obligated Mandatorily Redeemable Preferred Securities of SCE&G's Subsidiary Trust, SCE&G Trust I	—	—	50	50	50	—	—	50	50	50
Long-term Debt, net	3,186	3,225	2,834	2,646	2,850	1,981	2,010	1,604	1,486	1,343
Total Capitalization	$ 5,752	$ 5,646	$ 5,176	$ 5,006	$ 5,048	$ 4,260	$ 4,168	$ 3,735	$ 3,402	$ 3,166
Other Statistics(2)										
Electric:										
Customers (Year-End)	585,264	570,940	560,224	547,388	537,253	585,326	570,994	560,248	547,411	537,286
Total sales (Million KWh)	25,031	22,516	23,085	22,928	23,352	25,050	22,531	23,085	22,928	23,353
Generating capability—Net MW (Year-End)	5,817	4,880	4,866	4,520	4,544	5,817	4,880	4,251	3,905	3,929
Territorial peak demand—Net MW	4,574	4,474	4,404	4,196	4,211	4,574	4,474	4,404	4,196	4,211
Regulated Gas:										
Customers (Year-End)	691,067	670,770	655,669	645,749	637,018	282,250	276,384	272,053	267,206	266,451
Sales, excluding transportation (Thousand Therms)	1,124,555	1,205,730	1,354,400	1,183,463	1,389,975	399,601	399,392	398,991	368,632	444,521
Retail Gas Marketing:										
Retail customers (Year-End)	472,468	415,573	374,872	385,581	431,814	n/a	n/a	n/a	n/a	n/a
Firm customer deliveries (Thousand Therms)	379,712	356,256	337,858	359,602	431,115	n/a	n/a	n/a	n/a	n/a
Nonregulated interruptible customer deliveries (Thousand Therms)	917,875	735,902	852,608	1,119,719	1,506,057	n/a	n/a	n/a	n/a	n/a

(1) Reflects write-down of $230 million for goodwill impairment in 2002 upon adoption of SFAS 142.

(2) Other Statistics for 2000 exclude the effect of the change in accounting for unbilled revenues, where applicable.

SCANA CORPORATION

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Statements included in this discussion and analysis (or elsewhere in this annual report) which are not statements of historical fact are intended to be, and are hereby identified as, "forward-looking statements" for purposes of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Readers are cautioned that any such forward-looking statements are not guarantees of future performance and involve a number of risks and uncertainties, and that actual results could differ materially from those indicated by such forward-looking statements. Important factors that could cause actual results to differ materially from those indicated by such forward-looking statements include, but are not limited to, the following:(1) that the information is of a preliminary nature and may be subject to further and/or continuing review and adjustment, (2) regulatory actions or changes in the utility and nonutility regulatory environment, (3) current and future litigation, (4) changes in the economy, especially in areas served by subsidiaries of SCANA Corporation (SCANA, and together with its subsidiaries, the Company), (5) the impact of competition from other energy suppliers, including competition from alternate fuels in industrial interruptible markets, (6) growth opportunities for the Company's regulated and diversified subsidiaries, (7) the results of financing efforts, (8) changes in the Company's accounting policies, (9) weather conditions, especially in areas served by the Company's subsidiaries, (10) performance of the Company's pension plan assets, (11) inflation, (12) changes in environmental regulations, (13) volatility in commodity natural gas markets and (14) the other risks and uncertainties described from time to time in the Company's periodic reports filed with the SEC, including those risks described in Item 1 under Risk Factors. The Company disclaims any obligation to update any forward-looking statements.

OVERVIEW

SCANA is a registered holding company under PUHCA. Through its wholly owned regulated subsidiaries, SCANA is primarily engaged in the generation, transmission and distribution of electricity in parts of South Carolina and the purchase, transmission and sale of natural gas in portions of North Carolina and South Carolina. Through a wholly owned nonregulated subsidiary, SCANA markets natural gas to retail customers in Georgia and to wholesale customers primarily in the southeast. Other wholly owned nonregulated subsidiaries perform power plant management and maintenance services and provide service contracts to homeowners on certain home appliances and heating and air conditioning units. Additionally, a service company subsidiary of SCANA provides administrative, management and other services to the other subsidiaries.

Following are percentages of the Company's revenues and net income earned by regulated and nonregulated businesses and the percentage of total assets held by them.

% of Revenues	2004	2003	2002
Regulated	71%	73%	75%
Nonregulated	29%	27%	25%

% of Net Income (Loss)	2004(1)	2003	2002(2)
Regulated	106%	92%	10%
Nonregulated	(6)%	8%	(110)%

% of Assets	2004	2003	2002
Regulated	95%	93%	91%
Nonregulated	5%	7%	9%

(1) In 2004, net income for regulated businesses totaled $272.0 million and net loss for nonregulated businesses totaled $14.9 million. Net loss for nonregulated businesses included impairments and losses recognized on the sale of certain of the Company's telecommunications investments ($29.8 million, net of tax) and a charge related to pending litigation associated with the Company's 1999 sale of its propane assets ($11.1 million, net of taxes). See Results of Operations for more information.

(2) In 2002, net income for regulated businesses totaled $13.6 million and net loss for nonregulated businesses totaled $155.3 million. Net income for regulated subsidiaries included an impairment charge related to the acquisition adjustment associated with PSNC Energy ($230 million, net of tax). Net loss for nonregulated businesses included impairment charges for the Company's telecommunications investments ($189.2 million, net of tax), which were partially offset by gains the Company recognized from the sale of a radio service network ($9.4 million, net of tax) and the sale of DTAG shares ($15.3 million, net of tax). See Results of Operations for more information.

Electric Operations

The electric operations segment is comprised of the electric operations of SCE&G, GENCO and Fuel Company, and is primarily engaged in the generation, transmission and distribution of electricity in South Carolina. At December 31, 2004 SCE&G provided electricity to over 580,000 customers in an area of approximately 15,000 square miles. GENCO owns and operates a coal-fired generation station and sells electricity solely to SCE&G. Fuel Company acquires, owns and provides financing for SCE&G's nuclear fuel, fossil fuel and sulfur dioxide emission allowance requirements.

Operating results for electric operations are primarily driven by customer demand for electricity, the ability to control costs and rates allowed to be charged to customers. Embedded in the rates charged to customers is an allowed regulatory return on equity. The allowed return on equity for SCE&G was 12.45% in 2004. In January 2005, as a result of an electric rate case, the allowed return on equity was lowered to a range of 10.4% to 11.4%, with rates to be set at 10.7%. See further discussion at Liquidity and Capital Resources. Demand for electricity is primarily affected by weather, customer growth and the economy.

Legislative and regulatory initiatives also could significantly impact the results of operations and cash flows for the electric operations segment. In South Carolina the state legislature is not actively pursuing electric restructuring. However, both houses of the U.S. Congress introduced energy legislation in the 2003-2004 legislative sessions, but failed to reach a compromise on certain key issues unrelated to utilities. Energy legislation is expected to be reintroduced in 2005. It is anticipated that such legislation would include provisions that would repeal PUHCA and transfer additional regulatory authority to FERC. Provisions in the legislation would likely impose reliability standards for high-voltage transmission systems. New legislation may also impose stringent requirements on power plants to reduce emissions of sulfur dioxide, nitrogen oxides (NOx) and mercury. It is also possible that new initiatives will be introduced to reduce carbon dioxide emissions. The Company cannot predict whether such legislation will be enacted, and if it is, the conditions it would impose on utilities.

In April 2004 the joint U.S.-Canada Power System Outage Task Force issued its "Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations" (Blackout Report). The Blackout Report contains 46 recommendations that, if implemented, the Task Force believes would improve reliability of North America's interconnected bulk power system (the grid). Full implementation of the Blackout Report's recommendations would require a number of actions by legislative, regulatory and industry participants. However, the Blackout Report asserts as its single most important recommendation that the U.S. Congress should enact tougher reliability standards. It is anticipated that any reliability legislation, if passed, would make reliability standards mandatory and enforceable with penalties for non-compliance and would strengthen the role of FERC.

Regardless of the outcome of any legislative activity, FERC is expected to proceed with regulatory initiatives that, if enacted, could significantly change the country's existing regulatory framework governing transmission, open access and energy markets and would attempt, in large measure, to standardize the national energy market and attempt to disaggregate the remaining vertically integrated utilities. In July 2002 FERC issued a Notice of Proposed Rulemaking on Standard Market Design (SMD) which FERC supplemented with the issuance of a "white paper" in April 2003. If implemented, the proposed rule could have a significant impact on SCE&G's access to or cost of power for its native load customers and on SCE&G's marketing of power outside its service territory. The Company is currently evaluating FERC's action to determine potential effects on SCE&G's operations. Additional directives from FERC are expected.

The North American Electric Reliability Council (NERC) also is expected to continue its initiatives to develop, establish and enforce additional standards for the grid. To that end, NERC is working closely with FERC to implement stronger reliability standards among NERC's voluntary membership. SCE&G, along with other NERC members, is also working closely with NERC in these efforts. Such initiatives could be significantly influenced by any reliability legislation enacted by Congress. The Company cannot predict whether Congress will enact reliability legislation or the extent to which the other recommendations contained in the Blackout Report will be implemented. Any action by Congress or initiatives by FERC or NERC could significantly impact SCE&G's access to or cost of power for its native load customers and SCE&G's marketing of power outside its service territory.

Gas Distribution

The gas distribution segment is comprised of the distribution operations of SCE&G and PSNC Energy, and is primarily engaged in the purchase, transmission and sale of natural gas in portions of North Carolina and South Carolina. At December 31, 2004 this segment provided natural gas to more than 690,000 customers in an area of approximately 34,000 square miles.

Operating results for gas distribution are primarily influenced by customer demand for natural gas, the ability to control costs and allowed rates to be charged to customers. Embedded in the rates charged to customers is an allowed regulatory return on equity, which in 2004 was 12.25% for SCE&G and 11.4% for PSNC Energy. Demand for natural gas is primarily affected by weather, customer growth, the economy and, for commercial and industrial customers, the availability and price of alternate fuels. Natural gas competes with electricity, propane and heating oil to serve the heating and, to a lesser extent, other household energy needs of residential and small commercial customers. This competition is generally based on price and convenience. Large commercial and industrial customers often have the ability to switch from natural gas to an alternate fuel, such as propane or fuel oil. Natural gas competes with these alternate fuels based on price. As a result, any significant disparity between supply and demand, either of natural gas or of alternate fuels, and due either to production or delivery disruptions or other factors, will affect price and impact the Company's ability to retain large commercial and industrial customers.

Gas Transmission

For 2004 the gas transmission segment was comprised of SCPC, which owns and operates an intrastate pipeline engaged in the purchase, transmission and sale of natural gas on a wholesale basis to distribution companies (including SCE&G) and industrial customers throughout most of South Carolina. Operating results for 2004 were primarily influenced by customer demand for natural gas, the ability to control costs and allowed rates to be charged to customers. Embedded in these rates is an allowed regulatory return on equity, which in 2004 was 12.5% to 16.5%. Demand for natural gas is primarily affected by the price of alternate fuels and customer growth. SCPC supplies natural gas to SCE&G for its resale to gas distribution customers and for certain electric generation needs. SCPC also sells natural gas to large commercial and industrial customers in South Carolina and faces the same competitive pressures as the gas distribution segment for these classes of customers.

In 2005, SCANA expects to merge SCPC with another subsidiary, SCG Pipeline, which owns and operates an interstate pipeline that transports natural gas from southeast Georgia to South Carolina and delivers natural gas to SCE&G's Jasper County Electric Generating Station. The merger is subject to customary closing conditions and FERC approval. Assuming the merger is completed, the new company will operate as an interstate pipeline engaged in the transmission of natural gas in southeast Georgia and South Carolina. The new company's rates for transmission services, including an allowed return on equity, would be set and regulated by FERC.

Retail Gas Marketing

SCANA Energy, a division of SEMI, comprises the retail gas marketing segment. This segment markets natural gas to over 470,000 customers (as of December 31, 2004) throughout Georgia. SCANA Energy's total customer base represents about a 30 percent share of the approximately 1.5 million customers in Georgia's deregulated natural gas market. SCANA Energy remains the second largest natural gas marketer in the state. SCANA Energy's competitors include affiliates of other large energy companies with experience in Georgia's energy market as well as several electric membership cooperatives. SCANA Energy's ability to maintain its market share depends on the prices it charges customers relative to the prices charged by its competitors, its ability to continue to provide high levels of customer service and other factors. In addition, the pipeline capacity available for SCANA Energy to serve industrial and other customers is tied to the market share held by SCANA Energy in the retail market.

As Georgia's regulated provider, SCANA Energy serves low-income customers at rates approved by the GPSC and receives funding from the Universal Service Fund for bad debts. At December 31, 2004 SCANA Energy's regulated division served approximately 60,000 customers. In 2004 the GPSC extended SCANA Energy's term as the regulated provider through August 2005. In 2005, using a request for proposal process, the GPSC will select a regulated provider for the two-year period beginning September 1, 2005. SCANA Energy intends to submit a bid during this process.

SCANA Energy and SCANA's other natural gas distribution, transmission and marketing segments maintain gas inventory and also utilize forward contracts and financial instruments, including futures contracts and options, to manage their exposure to fluctuating commodity natural gas prices. See Note 9 to the consolidated financial statements. As a part of this risk management process, at any given time, a portion of SCANA's projected natural gas needs has been purchased or otherwise placed under contract. Since SCANA Energy operates in a competitive market, it may be unable to sustain its current levels of customers and/or pricing, thereby reducing expected margins and profitability.

Energy Marketing

The divisions of SEMI, excluding SCANA Energy, comprise the energy marketing segment. This segment markets natural gas primarily in the southeast and provides energy-related risk management services to producers and customers.

The operating results for energy marketing are primarily influenced by customer demand for natural gas and the ability to control costs. Demand for natural gas is primarily affected by the price of alternate fuels and customer growth.

RESULTS OF OPERATIONS

The Company's reported earnings (loss) are prepared in accordance with GAAP. Management believes that, in addition to reported earnings (loss) under GAAP, the Company's GAAP-adjusted net earnings from operations provides a meaningful representation of its fundamental earnings power and can aid in performing period-over-period financial analysis and comparison with peer group data. In management's opinion, GAAP-adjusted net earnings from operations is a useful indicator of the financial results of the Company's primary businesses. This measure is also a basis for management's provision of earnings guidance and growth projections, and it is used by management in making resource allocation and other budgetary and operational decisions. This non-GAAP performance measure is not intended to replace the GAAP measure of net earnings, but is offered as a supplement to it. A reconciliation of reported (GAAP) earnings (loss) per share to GAAP-adjusted net earnings from operations per share, as well as cash dividend information, is provided in the table below:

	2004	2003	2002
Reported (GAAP) earnings (loss) per share	$2.30	$2.54	$(1.34)
Less realized gains from sales of telecommunications investments and assets	—	(.35)	(.24)
Plus realized losses from sales of telecommunications investments and assets	.14	—	—
Plus telecommunications investment impairments	.13	.31	1.79
Plus charge related to pending litigation	.10	—	—
Plus cumulative effect of accounting change	—	—	2.17
GAAP-adjusted net earnings from operations per share	$2.67	$2.50	$ 2.38
Cash dividends declared (per share)	$1.46	$1.38	$ 1.30

Discussion of above adjustments:

Realized gains (losses) on telecommunications investments of $(.14), $.35 and $.24 were recognized in 2004, 2003 and 2002, respectively, and arose as a result of the Company's previously announced plans to monetize these telecommunications investments. All significant investments have now been monetized.

The after-tax loss of $.14 per share in 2004 relates to the sale of substantially all of the Company holdings in ITC^DeltaCom, Inc. (ITC^DeltaCom) and Knology, Inc. (Knology) in December of 2004. Proceeds from these sales in the amount of approximately $63 million, and the cash refund resulting from tax loss carrybacks to be received in 2005 (estimated to be $58 million) are expected to be used for debt reduction. The gain of $.35 per share in 2003 arose from the sale of the Company's interest in ITC Holding Company (ITC Holding) and the receipt of a minority investment interest in a newly formed entity, Magnolia Holding Company, LLC (Magnolia Holding). In 2002, the Company recognized after-tax gains of $.09 per share and $.15 per share related to the sale of a radio service network and shares of DTAG, respectively. The DTAG investment had been received in exchange for a previously held investment interest in Powertel, Inc. (Powertel).

Telecommunications investment impairments were recorded as follows:

	2004	2003	2002
DTAG	—	—	$(1.72)
ITC^DeltaCom	—	—	(.07)
Knology	$(.13)	$(.31)	—

As noted above, the Company exchanged a previous investment in Powertel for DTAG shares, resulting in the recording of a $3.38 per share gain in 2001. The DTAG shares experienced a significant decline in market value after that exchange but prior to their sale in 2002. The Company's ITC^DeltaCom shares experienced a significant impairment upon ITC^DeltaCom's filing for bankruptcy in 2002, while the Company's Knology holdings experienced other-than-temporary impairments in 2003 and 2004. As noted previously, the Company's investments in Knology and ITC^DeltaCom were monetized in December 2004.

Upon adoption of SFAS 142 in 2002, the Company recorded an impairment charge related to the goodwill recorded upon the acquisition of PSNC Energy. Annual evaluations of the carrying value of goodwill in subsequent periods have not resulted in similar charges.

In 2004, a jury issued its verdict in a case in which an unsuccessful bidder for the purchase of certain of SCANA's propane gas assets in 1999 alleged breach of contract and related claims. Based on this verdict, the Company recorded a charge of $.10 per share, its best estimate of the minimum award to be granted if the court's final judgment is consistent with the jury verdict and the Company's understanding of applicable law. It is expected that the final judgment will be rendered in 2005 but that appeals may continue for a longer period. See also Note 10 to the consolidated financial statements.

Management believes that all of the above adjustments are appropriate in determining the non-GAAP financial performance measure. Management utilizes such measure itself in exerting budgetary control, managing business operations and determining eligibility for incentive compensation payments. Such non-GAAP measure is based on management's decision that the telecommunications assets are not a part of the Company's core businesses and will not be available to provide earnings on a long-term basis. The non-GAAP measure also provides a consistent basis upon which to measure performance by properly excluding the effects on per share earnings of transactions involving the Company's telecommunications investments, the cumulative effect of adopting a new accounting standard and a litigation charge related to the sale of a prior business.

Pension Income

Pension income was recorded on the Company's financial statements as follows:

	2004	2003	2002
	Millions of dollars		
Income Statement Impact:			
(Component of) reduction in employee benefit costs	$ 2.9	$(2.3)	$10.9
Other income	10.8	7.9	11.1
Balance Sheet Impact:			
(Component of) reduction in capital expenditures	1.0	(0.5)	3.1
Component of (reduction in) amount due to Summer Station co-owner	0.4	(0.1)	0.7
Total Pension Income	$15.1	$ 5.0	$25.8

For the last several years, the market value of the Company's retirement plan (pension) assets has exceeded the total actuarial present value of accumulated plan benefits. Pension income's sharp decline in 2003 and its increase in 2004 are consistent with overall investment market results. See also the discussion of pension accounting in Critical Accounting Estimates.

Allowance for Funds Used During Construction (AFC)

AFC is a utility accounting practice whereby a portion of the cost of both equity and borrowed funds used to finance construction (which is shown on the balance sheet as construction work in progress) is capitalized. The Company includes an equity portion of AFC in nonoperating income and a debt portion of AFC in interest charges (credits) as noncash items, both of which have the effect of increasing reported net income. AFC represented approximately 6.6% of income before income taxes in 2004, 7.2% in 2003 and 25.8% in 2002. The ratio in 2002 was significantly higher than historical norms due to the inclusion in income before income taxes of $291 million of impairments related to the other than temporary decline in market value of the Company's investment in DTAG and ITC^DeltaCom.

In addition to the effect of impairments, the decrease in AFC for 2004 vs 2003 is partially due to completion of the Jasper County Electric Generating Station in May 2004. The decrease in AFC for 2003 vs 2002 is partially due to the completion of the Urquhart Station repowering project in June 2002. Also, in January 2003 the SCPSC issued an order allowing SCE&G to include all Jasper County generating project expenditures as of December 31, 2002 and other construction work in progress expenditures as of June 30, 2002 in its electric rate base. At the time the expenditures were included in the rate base, AFC was no longer calculated on those amounts. These decreases were partially offset by increased AFC from subsequent construction expenditures related to the Jasper County generating and Lake Murray Dam projects (see discussion at CAPITAL PROJECTS).

Electric Operations

Electric Operations is comprised of the electric operations of SCE&G, GENCO and Fuel Company. Electric operations sales margins for 2004, 2003 and 2002 were as follows:

	2004	% Change	2003	% Change	2002
	Millions of dollars				
Operating revenues	$1,687.7	15.1%	$1,466.5	6.3%	$1,379.5
Less: Fuel used in generation	466.9	39.7%	334.1	1.4%	329.6
Purchased power	50.7	(20.8)%	64.0	52.0%	42.1
Margin	$1,170.1	9.5%	$1,068.4	6.0%	$1,007.8

• 2004 vs 2003 Margin increased primarily due to increased off-system sales of $47.2 million, increased customer growth and consumption of $22.9 million, $22.3 million due to favorable weather and $7.1 million due to the increase in retail electric base rates effective February 2003. Fuel used in generation increased approximately $103.0 million due to increased availability of generation facilities and approximately $30.0 million due to increased cost of coal. Purchased power decreased due to greater availability of generation facilities.

• 2003 vs 2002 Margin increased primarily due to the increase in retail electric base rates effective February 2003 totaling $63.6 million and customer growth and increased consumption of $24.3 million, partially offset by $27.3 million due to less favorable weather. Fuel used in generation increased by $9.3 million due to the increased cost of natural gas and fuel oil for the Urquhart combined cycle gas turbines and by $1.1 million due to the increased cost of nuclear fuel, partially offset by $5.5 million due to planned plant outages throughout the year. Purchased power increased due to planned plant outages throughout the year.

MWh sales volumes by classes, related to the electric margin above, were as follows:

Classification (in thousands)	2004	% Change	2003	% Change	2002
Residential	7,460	6.6%	6,998	(3.2)%	7,230
Commercial	6,900	4.4%	6,607	(0.8)%	6,658
Industrial	6,775	3.5%	6,548	0.7%	6,505
Sales for resale (excluding interchange)	2,472	71.9%	1,438	(0.7)%	1,448
Other	526	5.2%	500	(6.5)%	535
Total territorial	24,133	9.2%	22,091	(1.3)%	22,376
NMST	898	*	425	(40.1)%	709
Total	25,031	11.2%	22,516	(2.5)%	23,085

* Greater than 100%

• 2004 vs 2003 Territorial sales volumes increased primarily due to more favorable weather, customer growth and consumption and increased off-system sales. NMST volumes increased primarily due to increased availability of generating plants that increased volumes available for resale.

• 2003 vs 2002 Territorial sales volume decreased primarily due to less favorable weather. NMST volumes decreased primarily due to planned outages at generation plants that reduced volumes available for resale.

Gas Distribution

Gas Distribution is comprised of the local distribution operations of SCE&G and PSNC Energy. Gas distribution sales margins (including transactions with affiliates) for 2004, 2003 and 2002 were as follows:

	2004	% Change	2003	% Change	2002
			Millions of dollars		
Operating revenues	$913.9	5.2%	$869.0	32.9%	$653.9
Less: Gas purchased for resale	655.1	9.3%	599.3	49.5%	401.0
Margin	$258.8	(4.0)%	$269.7	6.6%	$252.9

- 2004 vs 2003 Margin decreased primarily due to a decrease in SCE&G's billing surcharge for the recovery of environmental remediation expenses of $5.0 million, lower residential and commercial sales volumes of $2.5 million and $5.1 million due to milder weather. This was partially offset by customer growth at PSNC of $4.0 million.
- 2003 vs 2002 Margin increased primarily due to customer growth and increased consumption totaling $20.9 million, partially offset by a decrease in industrial usage of $4.1 million primarily due to an unfavorable competitive position of natural gas relative to alternate fuels.

DT sales volumes by classes, including transportation gas, were as follows:

Classification (in thousands)	2004	% Change	2003	% Change	2002
Residential	37,231	(3.4)%	38,542	8.0%	35,674
Commercial	27,271	(1.6)%	27,715	11.2%	24,927
Industrial	19,320	(3.9)%	20,109	(5.4)%	21,247
Transportation gas	28,216	11.1%	25,387	(15.8)%	30,166
Sales for resale	1	—	1	—	1
Total	112,039	0.3%	111,754	(0.2)%	112,015

- 2004 vs 2003 Residential and commercial sales volumes decreased primarily due to unfavorable consumption patterns. Transportation volumes increased in 2004 primarily as a result of interruptible customers using gas instead of alternative fuels.
- 2003 vs 2002 Residential and commercial sales volumes increased primarily due to more favorable weather. Industrial and transportation volumes decreased in 2003 primarily as a result of interruptible customers using their alternate fuel sources during the year.

Gas Transmission

Gas Transmission is comprised of the operations of SCPC. Gas transmission sales margins (including transactions with affiliates) for 2004, 2003 and 2002 were as follows:

	2004	% Change	2003	% Change	2002
			Millions of dollars		
Operating revenues	$550.9	6.0%	$519.8	8.5%	$479.1
Less: Gas purchased for resale	496.9	5.2%	472.2	6.7%	442.4
Margin	$ 54.0	13.4%	$ 47.6	29.7%	$ 36.7

- 2004 vs 2003 Margin increased primarily due to higher transportation and reservation revenue as a result of new firm transportation contracts.
- 2003 vs 2002 Margin increased primarily due to the favorable competitive position of natural gas relative to alternate fuels in the first quarter of $13.6 million, partially offset by the unfavorable competitive position of natural gas relative to alternate fuels in the second, third and fourth quarters of $1.5 million.

DT sales volumes by classes including transportation were as follows:

Classification (in thousands)	2004	% Change	2003	% Change	2002
Commercial	113	5.6%	107	(9.3)%	118
Industrial	28,625	(8.9)%	31,436	(32.5)%	46,578
Transportation	25,252	*	12,262	*	3,757
Sales for resale	42,946	(9.4)%	47,391	(16.7)%	56,906
Total	96,936	6.3%	91,196	(15.1)%	107,359

* Greater than 100%

- 2004 vs 2003 Industrial volumes decreased approximately 2.8 million DTs primarily due to decreased electric generation. Transportation volumes increased approximately 7.5 million DTs due to a new contract with a firm transportation customer and approximately 4.9 million DTs due to new transportation contracts with resale customers. Sales for resale volumes decreased approximately 4.4 million DTs primarily due to the new transportation contracts with resale customers stated above.
- 2003 vs 2002 Industrial volumes decreased approximately 6.0 million DTs due to decreased electric generation and approximately 8.8 million DTs due to competitiveness with alternate fuels. Transportation volumes increased approximately 9.1 million DTs and sales for resale volumes decreased approximately 9.4 million DTs primarily as a result of new transportation contracts with resale customers in 2003.

Retail Gas Marketing

Retail Gas Marketing is comprised of SCANA Energy, which operates in Georgia's natural gas market. Retail Gas Marketing revenues and net income for 2004, 2003 and 2002 were as follows:

	2004	% Change	2003	% Change	2002
	Millions of dollars				
Operating revenues	$552.0	23.1%	$448.3	18.1%	$379.5
Net income	29.0	44.3%	20.1	40.6%	14.3

- 2004 vs 2003 Operating revenues increased primarily as a result of increased volumes and higher average retail prices. Net income increased primarily due to higher margins of $16.7 million, partially offset by increased bad debt of $2.9 million, increased depreciation expense of $0.7 million and higher customer service expenses of $2.0 million.
- 2003 vs 2002 Operating revenues increased primarily as a result of higher average retail prices and increased volumes. Net income increased primarily due to increased margins of $10.8 million, partially offset by increased bad debt expense of $3.2 million, increased interest expense of $0.5 million and higher operating expenses of $0.3 million.

Delivered volumes for 2004, 2003 and 2002 totaled approximately 37.9 million, 35.6 million and 33.8 million DT, respectively.

Energy Marketing

Energy Marketing is comprised of the Company's non-regulated marketing operations, excluding SCANA Energy. Energy Marketing operating revenues and net loss for 2004, 2003 and 2002 were as follows:

	2004	% Change	2003	% Change	2002
	Millions of dollars				
Operating revenues	$596.5	43.5%	$415.7	31.2%	$316.8
Net loss	(2.0)	(81.8)%	(1.1)	(37.5)%	(0.8)

- 2004 vs 2003 Operating revenues increased $180.8 million due to higher market prices and higher sales volumes. Net loss increased primarily due to higher operating expenses of $2.0 million partially offset by higher margins of $0.8 million.
- 2003 vs 2002 Operating revenues increased $98.9 million which reflects a $146.0 million increase due to higher natural gas prices and a $45.9 million decrease due to lower volumes. Net loss increased primarily due to lower margins of $2.5 million partially offset by lower operating expenses of $2.3 million.

Delivered volumes for 2004, 2003 and 2002 totaled approximately 91.8 million, 73.6 million and 86.2 million DT, respectively. Delivered volumes increased in 2004 compared to 2003 primarily as a result of service to the Jasper County Electric Generating Station in 2004, which created 11.2 million DT of additional volume. Such intercompany sales are not eliminated, in accordance with SFAS 71 (see Note 1 to the consolidated financial statements). Delivered volumes decreased in 2003 compared to 2002 by approximately 2.7 million DT due to decreased industrial usage and by approximately 9.8 million DT due to fewer customers caused by a sluggish economy and related customer credit constraints.

Other Operating Expenses

Other operating expenses were as follows:

	2004	% Change	2003	% Change	2002
	Millions of dollars				
Other operation and maintenance	$ 607.5	8.8%	$558.3	6.9%	$522.2
Depreciation and amortization	265.1	11.2%	238.3	8.3%	220.0
Other taxes	145.6	4.6%	139.2	9.7%	126.9
Total	$1,018.2	8.8%	$935.8	7.7%	$869.1

- 2004 vs 2003 Other operation and maintenance expenses increased primarily due to increased labor and benefit expense of $26.3 million, higher bad debt expense of $5.8 million, increased expenses at the generation plants of $11.0 million, winter storm expense of $2.5 million and increased gas marketing and customer billing costs of $4.2 million, partially offset by increased pension income of $5.2 million. Depreciation and amortization increased by $13.4 million due to completion of the Jasper County Electric Generating Station and $11.1 million as a result of normal net property additions. Other taxes increased primarily due to increased property taxes.
- 2003 vs 2002 Other operation and maintenance expenses increased primarily due to lower pension income of $13.2 million, increased labor and benefit costs of $8.3 million, increased bad debt expense of $6.5 million, increased nuclear operating expenses of $4.5 million and increased other operating expenses of $3.6 million. Depreciation and amortization increased by $11.4 million due to normal net property additions, $4.2 million due to the completion of the Urquhart Station repowering project in June 2002 and $2.7 million due to amortization of franchise fees. Other taxes increased primarily due to increased property taxes.

Other Income

Components of other income, excluding the equity component of AFC, were as follows:

	2004	% Change	2003	% Change	2002
	Millions of dollars				
Gain (loss) on sale of investments	$(21.0)	*	$59.8	*	$ 23.6
Gain on sale of assets	0.7	(41.7)%	1.2	(92.7)%	16.4
Impairment of investments	(26.9)	(49.3)%	(53.1)	(81.7)%	(290.7)
Other income	24.2	(49.5)%	47.9	(0.8)%	48.3
Total	$(23.0)	*	$55.8	*	$(202.4)

* Greater than 100%

In 2004 the Company recognized a $21 million loss on the sale of investments in Knology and ITC^DeltaCom. In 2003 a $59.8 million gain on sale of investments was recognized in connection with the sale of ITC Holding and the receipt of an investment interest in a newly formed entity (Magnolia Holding). In 2002 $23.6 million was recognized upon the sale of the Company's DTAG stock. Gain on sale of assets in 2002 included the sale of the Company's radio system to Motorola. Impairments recorded in 2002 included those related to DTAG and ITC^DeltaCom, while impairments in 2003 related solely to the investment in Knology. In 2004 impairments of $26.9 million were recorded on

Knology, ITC Holding and Magnolia Holding. Other Income decreased primarily due to an $18 million charge related to pending litigation associated with the 1999 sale of the Company's propane assets.

Interest Expense

Components of interest expense, excluding the debt component of AFC, were as follows:

	2004	% Change	2003	% Change	2002
			Millions of dollars		
Interest on long-term debt, net	$208.1	1.4%	$205.2	0.1%	$205.0
Other interest expense	4.3	(25.9)%	5.8	(4.9)%	6.1
Total	$212.4	0.7%	$211.0	(0.1)%	$211.1

- 2004 vs 2003 Interest expense increased $1.4 million, primarily due to slightly higher levels of borrowing outstanding during 2004 until the payment of maturing debt late in the year.
- 2003 vs 2002 Interest expense remained almost flat due to an $8.5 million decrease as a result of lower interest rates (including the effect of swaps) which was partially offset by an $8.3 million increase due to additional borrowings.

Income Taxes

Income taxes decreased in 2004 compared to 2003 by $12.4 million and increased approximately $98.9 million in 2003 compared to 2002. Changes in income taxes are primarily due to changes in Other Income described above. The Company's effective tax rate for 2004, 2003 and 2002 was approximately 31.7%, 31.7% and 26.7%, respectively. The Company's effective tax rate has been favorably impacted in recent years by the flow-through of state investment tax credits and the recovery of the equity portion of AFC.

LIQUIDITY AND CAPITAL RESOURCES

Cash requirements for SCANA's regulated subsidiaries arise primarily from their operational needs, funding their construction programs and payment of dividends to SCANA. The ability of the regulated subsidiaries to replace existing plant investment, as well as to expand to meet future demand for electricity and gas, will depend on their ability to attract the necessary financial capital on reasonable terms. Regulated subsidiaries recover the costs of providing services through rates charged to customers. Rates for regulated services are generally based on historical costs. As customer growth and inflation occur and these subsidiaries continue their ongoing construction programs, rate increases will be sought. The future financial position and results of operations of the regulated subsidiaries will be affected by their ability to obtain adequate and timely rate and other regulatory relief, if requested.

In a January 2005 order the SCPSC granted SCE&G a composite increase in retail electric rates of approximately 2.89%, designed to produce additional annual revenues of approximately $41.4 million based on a test year calculation. The SCPSC lowered SCE&G's return on common equity from 12.45% to a range of between 10.4% and 11.4%, with rates to be set at 10.7%. The new rates became effective in January 2005. As part of its order, the SCPSC approved SCE&G's recovery of construction and operating costs for SCE&G's new Jasper County Electric Generating Station, recovery of costs of mandatory environmental upgrades primarily related to Federal Clean Air Act regulations and the application of current and anticipated net synthetic fuel tax credits to offset the cost of constructing the back-up dam at Lake Murray. The SCPSC also approved recovery over a five-year period of SCE&G's approximately $14 million of costs incurred in the formation of the GridSouth Regional Transmission

Organization and recovery through base rates over three years of approximately $25.6 million of purchased power costs that were previously deferred. As a part of its order, the SCPSC extended through 2010 its approval of the accelerated capital recovery plan for SCE&G's Cope Generating Station. Under the plan, based on the level of revenues and operating expenses, SCE&G may increase depreciation of its Cope Generating Station in excess of amounts that would be recorded based upon currently approved depreciation rates, not to exceed $36 million annually, without additional approval of the SCPSC. Any unused portion of the $36 million in any given year may be carried forward for possible use in the following year.

The Company's leverage ratio of debt to capital was 58% at December 31, 2004. The Company's goal is to reduce this leverage ratio to between 50% to 52%. If the agencies rating the Company's credit determine that the Company will not be able to achieve sufficient improvement in the leverage ratio, among other measures, these rating agencies may downgrade the Company's debt. Such a downgrade would adversely affect the interest rate the Company is able to obtain when issuing debt, would increase the rates applicable to the Company's short-term commercial paper programs and long-term debt and would limit the Company's access to capital markets. In order to bring the leverage ratio in line with rating agency expectations, the Company may apply cash flows from operations, sell equity securities, or a combination of the two.

In December 2004 SCH sold its investments in two telecommunications companies. The transactions resulted in a loss of $13.9 million after taxes, but generate after-tax cash proceeds of approximately $121.2 million (including cash related to certain tax benefits) which will be used to pay down debt.

The Company's current estimates of its cash requirements for construction and nuclear fuel expenditures for 2005-2007, which are subject to continuing review and adjustment, are as follows:

Estimated Cash Requirements

	2005	2006	2007
	Millions of dollars		
SCE&G:			
Electric Plant:			
Generation (including GENCO)	$ 86	$145	$101
Transmission	44	51	27
Distribution	115	110	107
Other	15	16	17
Nuclear Fuel	23	26	25
Gas	30	30	28
Common	31	13	12
Other	4	1	—
Total SCE&G	348	392	317
PSNC Energy	57	62	63
Other Companies Combined	40	33	54
Total	$445	$487	$434

The Company's contractual cash obligations as of December 31, 2004 are summarized as follows:

Contractual Cash Obligations

December 31, 2004 (Millions of dollars)	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
Long-term and short-term debt (including interest and preferred stock)	$ 6,303	$ 637	$1,068	$ 447	$4,151
Capital leases	2	1	1	—	—
Operating leases	56	15	33	8	—
Purchase obligations	166	95	63	6	2
Other commercial commitments	6,850	1,162	1,817	814	3,057
Total	$13,377	$1,910	$2,982	$1,275	$7,210

Included in other commercial commitments are estimated obligations under forward contracts for natural gas purchases. Many of these forward contracts include customary "make-whole" or default provisions, but are not considered to be "take-or-pay" contracts. Certain of these contracts relate to regulated businesses; therefore, the effects of such contracts on fuel costs are reflected in electric or gas rates. Also included in other commercial commitments is a 15-year "take-and-pay" contract for natural gas, estimated obligations for coal and nuclear fuel purchases and certain obligations related to the Lake Murray Dam reinforcement project. See Note 10 to the consolidated financial statements.

Included in purchase obligations are customary purchase orders under which the Company has the option to utilize certain vendors without the obligation to do so. The Company may terminate such obligations without penalty.

In addition to the contractual cash obligations above, the Company sponsors a noncontributory defined benefit pension plan and an unfunded health care and life insurance benefit plan for retirees. The pension plan is adequately funded, and no further contributions are anticipated until after 2009. Cash payments under the health care and life insurance benefit plan were approximately $11.5 million in 2004, and such payments are expected to increase to the $13-$14 million range in the future.

In addition, the Company is party to certain NYMEX futures contracts for which any unfavorable market movements are funded in cash. These derivatives are accounted for as cash flow hedges under SFAS 133, *"Accounting for Derivative Instruments and Hedging Activities,"* as amended, and their effects are reflected within other comprehensive income until the anticipated sales transactions occur.

The Company also has a legal obligation associated with the decommissioning and dismantling of Summer Station that is not listed in the contractual cash obligations above. See Note 1 to the consolidated financial statements.

The Company anticipates that its contractual cash obligations will be met through internally generated funds, issuance of equity under dividend reinvestment and employee stock ownership plans, the incurrence of additional short-term and long-term indebtedness and other sales of equity securities. The Company expects that it has or can obtain adequate sources of financing to meet its projected cash requirements for the foreseeable future.

Cash outlays for 2005 (estimated) and 2004 (actual) for certain expenditures are as follows:

	2005	2004
	Millions of dollars	
Property additions and construction expenditures, net of AFC	$422	$499
Nuclear fuel expenditures	23	22
Investments	18	19
Total	$463	$540

Included in cash outlays are the following specific projects:

- FERC mandated that SCE&G's Lake Murray Dam be reinforced to comply with new federal safety standards. Construction for the project and related activities is expected to be complete in 2005 at a cost of approximately $275 million (excluding AFC), of which approximately $240 million had been incurred through December 31, 2004.
- SCE&G completed construction of its 880 MW generation plant in Jasper County, South Carolina in May 2004. The plant includes three natural gas combustion-turbine generators and one steam-turbine generator. The total cost of the project was approximately $506 million, which includes the original construction costs for the plant itself, as well as AFC and other project-related costs. All such costs have been approved for recovery in rate base.
- Construction of SCPC's South System Loop was completed in 2004 at a cost of approximately $21 million. This natural gas pipeline stretches 38.3 miles from SCG Pipeline's connection with SCE&G's Jasper County Electric Generating Station to Yemassee in Hampton County, South Carolina, providing a new gas supply source to SCPC's current system.

Financing Limits and Related Matters

The Company's issuance of various securities, including long-term and short-term debt, is subject to customary approval or authorization by state and federal regulatory bodies including state public service commissions and the SEC. The following describes the financing programs currently utilized by the Company.

At December 31, 2004 SCANA, SCE&G (including Fuel Company) and PSNC Energy had available the following lines of credit and short-term borrowings outstanding:

	SCANA	SCE&G	PSNC Energy
	Millions of dollars		
Lines of credit (total and unused):			
Committed			
Short-term	$100	—	—
Long-term (expires June 2009)	—	$ 525	$ 125
Uncommitted	113[(1)]	113[(1)]	—
Short-term borrowings outstanding:			
Commercial paper (270 or fewer days)	—	$152.9	$57.8
Weighted average interest rate	—	2.40%	2.47%

(1) Lines of credit that either SCANA or SCE&G may use.

SCANA Corporation

SCANA has in effect a medium-term note program for the issuance from time to time of unsecured medium-term debt securities. While issuance of these securities requires customary approvals discussed above, the Indenture under which they are issued contains no specific limit on the amount which may be issued.

South Carolina Electric & Gas Company

SCE&G's First and Refunding Mortgage Bond Indenture, dated January 1, 1945 (Old Mortgage) and covering substantially all of its properties, prohibits the issuance of additional bonds (Class A Bonds) unless net earnings (as therein defined) for 12 consecutive months out of the 18 months prior to the month of issuance are at least twice the annual interest requirements on all Class A Bonds to be outstanding (Bond Ratio). For the year ended December 31, 2004 the Bond Ratio was 5.72. The Old Mortgage allows the issuance of Class A Bonds up to an additional principal amount equal to (i) 70% of unfunded net property additions (which unfunded net property additions totaled approximately $1,401.2 million at December 31, 2004), (ii) retirements of Class A Bonds (which retirement credits totaled $121.4 million at December 31, 2004), and (iii) cash on deposit with the Trustee.

SCE&G is also subject to a bond indenture dated April 1, 1993 (New Mortgage) covering substantially all of its electric properties under which its future mortgage-backed debt (New Bonds) will be issued. New Bonds are issued under the New Mortgage on the basis of a like principal amount of Class A Bonds issued under the Old Mortgage which have been deposited with the Trustee of the New Mortgage. At December 31, 2004 approximately $1.0 billion Class A Bonds were on deposit with the Trustee of the New Mortgage and are available to support the issuance of additional New Bonds. New Bonds will be issuable under the New Mortgage only if adjusted net earnings (as therein defined) for 12 consecutive months out of the 18 months immediately preceding the month of issuance are at least twice the annual interest requirements on all outstanding bonds (including Class A Bonds) and New Bonds to be outstanding (New Bond Ratio). For the year ended December 31, 2004 the New Bond Ratio was 5.57.

SCE&G's Restated Articles of Incorporation (the Articles) prohibit issuance of additional shares of preferred stock without the consent of the preferred shareholders unless net earnings (as defined therein) for the 12 consecutive months immediately preceding the month of issuance are at least one and one-half times the aggregate of all interest charges and preferred stock dividend requirements on all shares of preferred stock outstanding immediately after the proposed issue (Preferred Stock Ratio). For the year ended December 31, 2004 the Preferred Stock Ratio was 1.71.

The Articles also require the consent of a majority of the total voting power of SCE&G's preferred stock before SCE&G may issue or assume any unsecured indebtedness if, after such issue or assumption, the total principal amount of all such unsecured indebtedness would exceed ten percent of the aggregate principal amount of all of SCE&G's secured indebtedness and capital and surplus (the ten percent test). No such consent is required to enter into agreements for payment of principal, interest and premium for securities issued for pollution control purposes. At December 31, 2004 the ten percent test would have limited issuances of unsecured indebtedness to approximately $415.3 million. Unsecured indebtedness at December 31, 2004 totaled approximately $154.1 million, and was comprised of short-term borrowings and the interest-free borrowing discussed below.

In 2004 SCE&G borrowed $35.4 million under an agreement with the South Carolina Transportation Infrastructure Bank (the Bank) and the South Carolina Department of Transportation (SCDOT) that allows SCE&G to borrow funds from the Bank to construct a roadbed for SCDOT in connection with the Lake Murray Dam remediation project. The loan agreement provides for interest-free borrowings of up to $59 million with such borrowings being repaid over ten years from the initial borrowing. At December 31, 2004 SCE&G had $32.5 million outstanding under the agreement.

Public Service Company of North Carolina, Incorporated

PSNC Energy has in effect a medium-term note program for the issuance from time to time of unsecured medium-term debt securities. While issuance of these securities requires regulatory approval, the Indenture under which they would be issued contains no specific limit on the amount which may be issued.

Financing Cash Flows

During 2004 the Company experienced net cash outflows related to financing activities of approximately $124 million primarily due to the reduction of long- and short-term debt and payment of dividends. SCE&G also experienced net cash outflows related to financing activities of approximately $110 million primarily due to the payment of dividends.

The Company uses interest rate swap agreements to manage interest rate risk. These swap agreements provide for the Company to pay variable and receive fixed rate interest payments and are designated as fair value hedges of certain debt instruments. The Company may terminate a swap agreement and may replace it with a new swap also designated as a fair value hedge. Payments received upon termination of such swaps are recorded as basis adjustments to long-term debt and are amortized as reductions to interest expense over the term of the underlying debt. At December 31, 2004 the estimated fair value of the Company's swaps totaled $4.2 million (gain) related to combined notional amounts of $275.6 million.

In anticipation of the issuance of debt, the Company may use interest rate locks or similar agreements to manage interest rate risk. Payments received or made upon termination of such agreements are recorded within other deferred debits or credits on the balance sheet and are amortized to interest expense over the term of the underlying debt.

For additional information on significant financing transactions, see Note 4 to the consolidated financial statements.

On February 17, 2005 SCANA increased the quarterly cash dividend rate on SCANA common stock to $.39 per share, an increase of 6.8%. The new dividend is payable April 1, 2005 to stockholders of record on March 10, 2005.

ENVIRONMENTAL MATTERS

Capital Expenditures

In the years 2002 through 2004, the Company's capital expenditures for environmental control totaled approximately $270.4 million. These expenditures were in addition to expenditures included in "Other operation and maintenance" expenses, which were approximately $21.5 million, $29.2 million, and $29.9 million during 2004, 2003 and 2002, respectively. It is not possible to estimate all future costs related to environmental matters, but forecasts for capitalized environmental expenditures for the Company are $31.7 million for 2005 and $360.4 million for the four-year period 2006 through 2009. These expenditures are included in the Company's construction program, discussed in Liquidity and Capital Resources, and include the matters discussed below.

Electric Operations

The CAA required electric utilities to substantially reduce emissions of sulfur dioxide and NOx by the year 2000. The Company remains in compliance with these requirements. In 1998 the EPA required the State of South Carolina, among other states, to modify its state implementation plan (SIP) to address the issue of NOx pollution. South Carolina's SIP requires additional emissions reductions in 2004 and beyond. Further, the EPA had indicated that it would finalize regulations by March 2005 for stricter limits on mercury generated by coal-fired plants. Further reductions in sulfur dioxide and NOx are expected to be proposed in 2005. New legislation may also impose stringent requirements on power plants to reduce emissions of sulfur dioxide, NOx and mercury. It is also possible that new initiatives will be introduced to reduce carbon dioxide emissions. The Company cannot predict whether such legislation will be enacted, and if it is, the conditions the legislation would impose on utilities.

The EPA has undertaken an aggressive enforcement initiative against the utilities industry, and the DOJ has brought suit against a number of utilities in federal court alleging violations of the CAA. At least two of these suits have either been tried or have had substantive motions decided—one favorable to the industry and one not. Neither is binding as precedent on the Company. Prior to the suits, those utilities had received requests for information under Section 114 of the CAA and were issued Notices of Violation. The basis for these suits is the assertion by the EPA, under a stringent rule known as New Source Review (NSR), that maintenance activities undertaken by the utilities over the past 20 or more years constitute "major modifications" which would have required the installation of costly Best Available Control Technology (BACT). SCE&G and GENCO have received and responded to Section 114 requests for information related to Canadys, Wateree and Williams Stations. The regulations under the CAA provide certain exemptions to the definition of "major modifications," including an exemption for routine repair, replacement or maintenance. On October 27, 2003 EPA published a final revised NSR rule in the Federal Register with an effective date of December 26, 2003. The new rule represents an industry-favorable departure from certain positions advanced by the federal government in the NSR enforcement initiative. However, on motion of several Northeastern states, the United States Circuit Court of Appeals for the District of Columbia stayed the effect of the final rule. The ultimate application of the final rule to the Company is uncertain. The Company has analyzed each of the activities covered by the EPA's requests and believes each of these activities is covered by the exemption for routine repair, replacement and maintenance under what it believes is a fair reading of both the prior regulation and the contested revised regulation. The regulations also provide an exemption for an increase in emissions resulting from increased hours of operation or production rate and from demand growth. The current state of continued DOJ enforcement actions is the subject of industry-wide speculation, but it is possible that the EPA will commence enforcement actions against SCE&G and GENCO, and the EPA has the authority to seek penalties at the rate of up to $27,500 per day for each violation. The EPA also could seek installation of BACT (or equivalent) at the three plants. The Company believes that any enforcement actions relative to the Company's, SCE&G's or GENCO's compliance with the CAA would be without merit. However, if successful, such actions could have a material adverse effect on the Company's financial condition, cash flows and results of operations. To comply with current and anticipated state and federal regulations, SCE&G and GENCO expect to incur capital expenditures totaling approximately $193.3 million over the 2005-2008 period to retrofit existing facilities, with increased operation and maintenance costs of approximately $2.4 million per year. SCE&G and GENCO expect to have increased operation and maintenance costs of approximately $9.6 million in 2009. To meet compliance requirements for the years 2010 through 2014, the Company anticipates additional capital expenditures totaling approximately $160.1 million.

The Clean Water Act, as amended, provides for the imposition of effluent limitations that require treatment for wastewater discharges. Under this Act, compliance with applicable limitations is achieved under a national permit program. Discharge permits have been issued for all, and renewed for nearly all, of SCE&G's and GENCO's generating units. Concurrent with renewal of these permits, the permitting agency has implemented a more rigorous program of monitoring and controlling thermal discharges, has modified the requirements for cooling water intake structures, and has required strategies for toxicity reduction in wastewater streams. The Company is developing compliance plans for these initiatives. Congress is expected to consider further amendments to the Clean Water Act. Such legislation may include limitations to mixing zones and toxicity-based standards. These provisions, if passed, could have a material impact on the financial condition, results of operations and cash flows of the Company, SCE&G and GENCO.

Nuclear Fuel Disposal

The Nuclear Waste Policy Act of 1982 required that the United States government, by January 31, 1998, accept and permantly dispose of high-level radioactive waste and spent nuclear fuel and imposes a fee of 1.0 mil per KWh of net nuclear generation after April 7, 1983. The Act also imposes on utilities the primary responsibility for storage of their spent nuclear fuel until the repository is available. SCE&G entered into a Standard Contract for Disposal of Spent Nuclear Fuel and/or High-Level Radioactive Waste (Standard Contract) with the DOE in 1983 providing for permanent disposal of its spent nuclear fuel in exchange for agreed payments at particular amounts. On January 28, 2004 SCE&G and Santee Cooper (one-third owner of Summer Station) filed suit in the Court of Federal Claims against the DOE for breach of the Standard Contract, because as of the date of filing, the federal government has accepted no spent fuel from Summer Station or any other utility for transport and disposal, and has indicated that it does not anticipate doing so until 2010, at the earliest. As a consequence of the federal government's breach of contract, the plaintiffs have incurred and will continue to incur substantial costs. There are two additional causes of action alleged as well—damages for breach of the implied covenant of good faith and fair dealing and a takings claim demanding just compensation for the taking of the plaintiffs' real property through the cost of storage. SCE&G has on-site spent nuclear fuel storage capability until at least 2018 and expects to be able to expand its storage capacity to accommodate the spent nuclear fuel output for the life of the plant through dry cask storage or other technology as it becomes available.

Gas Distribution

The Company maintains an environmental assessment program to identify and evaluate current and former operations sites that could require environmental cleanup. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and clean up each site. These estimates are refined as additional information becomes available; therefore, actual expenditures may differ significantly from the original estimates. Amounts estimated and accrued to date for site assessments and cleanup relate solely to regulated operations and are recorded in deferred debits and amortized with recovery provided through rates.

Deferred amounts for SCE&G, net of amounts previously recovered through rates and insurance settlements, totaled $10.5 million and $10.9 million at December 31, 2004 and 2003, respectively. The deferral includes the estimated costs associated with the following matters.

- SCE&G owns a decommissioned MGP site in the Calhoun Park area of Charleston, South Carolina. The site is currently being remediated for contamination. SCE&G anticipates that the remaining remediation activities will be completed by the end of 2005, with certain monitoring and other activities continuing until 2010. As of December 31, 2004, SCE&G has spent approximately $20.5 million to remediate the Calhoun Park site, and expects to spend an additional $1.3 million. In addition, SCE&G is party to certain claims for costs and damages from this site, for which claims the National Park Service of the Department of the Interior made an initial demand for payment of approximately $9 million. Any costs arising from these matters are expected to be recoverable through rates under South Carolina regulatory processes.
- SCE&G owns three other decommissioned MGP sites in South Carolina which contain residues of by-product chemicals. One of the sites has been remediated and will undergo routine monitoring until released by DHEC. The other two sites are currently being investigated under work plans approved by DHEC. SCE&G anticipates that major remediation activities for the three sites will be completed in 2010. As of December 31, 2004, SCE&G has spent approximately $4 million related to these three sites, and expects to spend an additional $4 million.

PSNC Energy is responsible for environmental cleanup at five sites in North Carolina on which MGP residuals are present or suspected. PSNC Energy's actual remediation costs for these sites will depend on a number of factors, such as actual site conditions, third-party claims and recoveries from other PRPs. PSNC Energy has recorded a liability and associated regulatory asset of approximately $6.5 million, which reflects the estimated remaining liability at December 31, 2004. Amounts incurred and deferred to date, net of insurance settlements, that are not currently being recovered through gas rates are approximately $1.4 million. Management believes that all MGP cleanup costs incurred will be recoverable through gas rates.

REGULATORY MATTERS

Material retail rate proceedings are described in more detail in Note 2 to the consolidated financial statements.

South Carolina Electric & Gas Company

SCE&G is subject to the jurisdiction of the SCPSC as to retail electric and gas rates, service, accounting, issuance of securities (other than short-term borrowings) and other matters.

In a January 2005 order the SCPSC granted SCE&G a composite increase in retail electric rates of approximately 2.89%, designed to produce additional annual revenues of approximately $41.4 million based on a test year calculation. The SCPSC lowered SCE&G's return on common equity from 12.45% to a range of between 10.4% and 11.4%, with rates to be set at 10.7%. The new rates became effective in January 2005. As part of its order, the SCPSC approved SCE&G's recovery of construction and operating costs for SCE&G's new Jasper County Electric Generating Station, recovery of costs of mandatory environmental upgrades primarily related to Federal Clean Air Act regulations and the application of current and anticipated net synthetic fuel tax credits to offset the cost of constructing the back-up dam at Lake Murray. The SCPSC also approved recovery over a five-year period of SCE&G's approximately $14 million of costs incurred in the formation of the GridSouth Regional Transmission Organization and recovery through base rates over three years of approximately $25.6 million of purchased power costs that were previously deferred. As a part of its order, the SCPSC extended through 2010 its approval of the accelerated capital recovery plan for SCE&G's Cope Generating Station. Under the plan, based on the level of revenues and operating expenses, SCE&G may increase depreciation of its Cope Generating Station in excess of amounts that would be recorded based upon currently approved depreciation rates, not to exceed $36 million annually, without additional approval of the SCPSC. Any unused portion of the $36 million in any given year may be carried forward for possible use in the following year.

Synthetic Fuel Investments

SCE&G holds two equity-method investments in partnerships involved in converting coal to non-conventional fuel, the use of which fuel qualifies for federal income tax credits. The aggregate investment in these partnerships as of December 31, 2004 is approximately $3.4 million, and through December 31, 2004, they have generated and passed through to SCE&G approximately $140.5 million in such tax credits. At December 31, 2004 SCE&G has recorded on its balance sheet $96.7 million net deferred synthetic fuel tax benefits, which includes the effects of partnership losses. In addition, Primesouth, Inc., a non-regulated subsidiary of SCANA, operates a synthetic fuel facility for a third party and receives management fees, royalties and expense reimbursements related to these services. Primesouth does not benefit from any synfuel tax credits.

Under a plan approved by the SCPSC, any tax credits generated by the partnerships and ultimately passed through to SCE&G from synfuel produced for and consumed by SCE&G, net of partnership losses and other expenses, have been and will be deferred and will be applied to offset the capital costs of constructing the back-up dam at Lake Murray. See Note 2 to the consolidated financial statements.

In March 2004, one of the partnerships, S.C. Coaltech No. 1 L.P., received a "No Change" letter from the Internal Revenue Service (IRS) related to its synthetic fuel operations for the tax year 2000. After review of testing procedures and supporting documentation and conducting an independent investigation, the IRS found that the partnership produces a qualifying fuel under section 29 of the Internal Revenue Code (IRC) and found no reason to challenge the first placed-in-service status of the facility. This letter supports SCANA's position that the synthetic fuel tax credits have been properly claimed.

In order to earn these tax credits, SCANA must be subject to a regular federal income tax liability in an amount at least equal to the credits generated in any taxable year. This tax liability could be insufficient if the Company's consolidated taxable income were to be significantly reduced as the result of realizing lower income or large deductions in any taxable year.

Section 29 of the IRC provides for the reduction of synthetic fuel tax credits for any calendar year in which the average annual wellhead price of oil exceeds an inflation-adjusted base price per barrel (as defined in the IRC, and currently estimated to be approximately $52), up to a maximum price spread (as defined in the IRC, and currently estimated to be in the range of $12-$13), at which point the credits would be completely phased-out. The Company cannot predict what impact, if any, the price of oil may have on the Company's ability to earn synthetic fuel tax credits in the future.

The availability of these synthetic fuel tax credits is also subject to coal availability and other operational risks related to the generating plants, including those described in the Risk Factors section within Item 1, Business.

Nuclear License Extension

In April 2004 the NRC approved SCE&G's application for a 20-year license extension for its Summer Station. The extension allows the plant to operate through August 6, 2042.

Public Service Company of North Carolina, Incorporated

PSNC Energy is subject to the jurisdiction of the NCUC as to gas rates, issuance of securities (other than notes with a maturity of two years or less or renewals of notes with a maturity of six years or less), accounting and other matters. As a condition to obtaining the NCUC's approval of SCANA's acquisition of PSNC Energy, PSNC Energy agreed to a moratorium on general rate increases until after August 2005. General rate relief can be obtained to recover costs associated with materially adverse governmental actions and force majeure events.

The U. S. Congress passed the Pipeline Safety Improvement Act of 2002 (the Pipeline Safety Act), directing the U. S. Department of Transportation to establish a pipeline integrity management rule for operations of natural gas systems with transmission pipelines located near moderate to high density populations. Of PSNC Energy's approximately 720 miles of transmission pipeline subject to the Pipeline Safety Act, approximately 110 miles are located within these areas. Fifty percent of these miles of pipeline must be assessed by December 2007, and the remainder by December 2012. Depending on the assessment method used, PSNC Energy will be required to reinspect these same miles of pipeline every five to seven years. Though cost estimates for this project were developed using various assumptions, each of which are subject to imprecision, PSNC Energy currently estimates the total cost to be $10 million for the initial assessments and any subsequent remediation required through December 2012. On January 21, 2005 the NCUC authorized the Company to defer for subsequent rate consideration certain expenses incurred to comply with DOT's pipeline integrity management requirements. This accounting treatment was effective November 1, 2004.

South Carolina Pipeline Corporation

SCPC has approximately 70 miles of transmission line that are covered by the Pipeline Safety Act. Total costs for compliance with the Pipeline Safety Act have not been determined.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Following are descriptions of the Company's accounting policies which are most critical in terms of reporting financial condition or results of operations.

Utility Regulation

SCANA's regulated utilities are subject to the provisions of SFAS 71, *"Accounting for the Effects of Certain Types of Regulation,"* which require them to record certain assets and liabilities that defer the recognition of expenses and revenues to future periods as a result of being rate-regulated. In the future, as a result of deregulation or other changes in the regulatory environment, the Company may no longer meet the criteria for continued application of SFAS 71 and could be required to write off its regulatory assets and liabilities. Such an event could have a material adverse effect on the results of operations of the Company's Electric Distribution and Gas Distribution segments in the period the write-off would be recorded. It is not expected that cash flows or financial position would be materially affected. See Note 1 to the consolidated financial statements for a description of the Company's regulatory assets and liabilities, including those associated with the Company's environmental assessment program.

The Company's generation assets would be exposed to considerable financial risks in a deregulated electric market. If market prices for electric generation do not produce adequate revenue streams and the enabling legislation or regulatory actions do not provide for recovery of the resulting stranded costs, the Company could be required to write down its investment in those assets. The Company cannot predict whether any write-downs will be necessary and, if they are, the extent to which they would adversely affect the Company's results of operations in the period in which they would be recorded. As of December 31, 2004 the Company's net investments in fossil/hydro and nuclear generation assets were approximately $2.5 billion and $556 million, respectively.

Revenue Recognition and Unbilled Revenues

Revenues related to the sale of energy are recorded when service is rendered or when energy is delivered to customers. Because customers of the Company's utilities and retail gas operations are billed on cycles which vary based on the timing of the actual reading of their electric and gas meters, the Company records estimates for unbilled revenues at the end of each reporting period. Such unbilled revenue amounts reflect estimates of the amount of energy delivered to each customer since the date of the last reading of their respective meters. Such unbilled revenues reflect consideration of estimated usage by customer class, the effects of different rate schedules, changes in weather and, where applicable, the impact of weather normalization provisions of rate structures. The accrual of unbilled revenues in this manner properly matches revenues and related costs. As of December 31, 2004 and 2003, accounts receivable included unbilled revenues of $180.5 million and $134.5 million, respectively, compared to total revenues for 2004 and 2003 of $3.9 billion and $3.4 billion, respectively.

Provisions for Bad Debts and Allowances for Doubtful Accounts

As of each balance sheet date, the Company evaluates the collectibility of accounts receivable and records allowances for doubtful accounts based on estimates of the level of expected write-offs. These estimates are based on, among other things, comparisons of the relative age of accounts, assigned credit ratings for commercial and industrial accounts, and consideration of actual write-off history. The distribution segments of the Company's regulated utilities have established write-off histories and regulated service areas that enable the utilities to reliably estimate their respective provisions for bad debts. The Company's Retail Gas Marketing segment operates in Georgia's deregulated natural gas market. As such, estimation of the provision for bad debts related to this segment is subject to greater imprecision.

Nuclear Decommissioning

Accounting for decommissioning costs for nuclear power plants involves significant estimates related to costs to be incurred many years in the future. Among the factors that could change SCE&G's accounting estimates related to decommissioning costs are changes in technology, changes in regulatory and environmental remediation requirements, and changes in financial assumptions such as discount rates and timing of cash flows. Changes in any of these estimates could significantly impact the Company's financial position and cash flows (although changes in such estimates should be earnings-neutral, because these costs are expected to be collected from ratepayers).

SCE&G's share of estimated site-specific nuclear decommissioning costs for Summer Station, including the cost of decommissioning plant components not subject to radioactive contamination, totals approximately $357 million, stated in 1999 dollars. This estimate is based on a decommissioning study completed in 2000 and has not been updated to incorporate the 20-year license extension for Summer Station received in 2004. Santee Cooper is responsible for decommissioning costs related to its one-third ownership interest in the station. The cost estimate is based on a decommissioning methodology acceptable to the NRC under which the site would be maintained over a period of approximately 60 years in such a manner as to allow for subsequent decontamination that permits release for unrestricted use.

Under SCE&G's method of funding decommissioning costs, funds collected through rates are invested in insurance policies on the lives of certain Company personnel. SCE&G is the beneficiary of these policies. Through these insurance contracts, SCE&G is able to take advantage of income tax benefits and accrue earnings on a tax-deferred basis. Amounts for decommissioning collected through electric rates, insurance proceeds, and interest on proceeds, less expenses, are transferred by SCE&G to an external trust fund. Management intends for the fund, including earnings thereon, to provide for all eventual decommissioning expenditures on an after-tax basis.

Accounting for Pensions and Other Postretirement Benefits

SCANA follows SFAS 87, *"Employers' Accounting for Pensions,"* in accounting for its defined benefit pension plan. SCANA's plan is fully funded and as such, net pension income is reflected in the financial statements (see Results of Operations). SFAS 87 requires the use of several assumptions, the selection of which may have a large impact on the resulting benefit recorded. Among the more sensitive assumptions are those surrounding discount rates and returns on assets. Net pension income of $15.1 million recorded in 2004 reflects the use of a 6.0% discount rate and an assumed 9.25% long-term rate of return on plan assets. SCANA believes that these assumptions were, and that the resulting pension income amount was, reasonable. For purposes of comparison, using a discount rate of 5.75% in 2004 would have increased SCANA's pension income by approximately $0.3 million. Had the assumed long-term rate of return on assets been reduced to 9.0% in 2004, SCANA's pension income would have been reduced by approximately $1.9 million.

In determining the appropriate discount rate, the Company considers the market indices of high-quality long-term fixed income securities. As such, the Company selected the beginning of year discount rate of 6.0% as being within a reasonable range of interest rates for obligations rated Aa by Moody's as of January 1, 2004. This same discount rate was also selected for determination of other postemployment benefits costs discussed below.

The following information with respect to pension assets (and returns thereon) should also be noted:

The Company determines the fair value of substantially all of its pension assets utilizing market quotes rather than utilizing any calculated values, “market related” values or other modeling techniques. In developing the expected long-term rate of return assumptions, the Company evaluated input from actuaries and from pension fund investment advisors, including such advisors’ review of the plan’s historical 10, 15, 20 and 25 year cumulative actual returns of 12.1%, 11.3%, 12.5% and 12.7%, respectively, all of which have been in excess of related broad indices. The Company anticipates that the investment managers will continue to generate long-term returns of at least 9.25%.

The expected long-term rate of return of 9.25% is based on a target asset allocation of 70% with equity managers and 30% with fixed income managers. Management regularly reviews such allocations and periodically rebalances the portfolio to the targeted allocation when considered appropriate.

While investment performance in 2000-2002 and lower discount rates have significantly reduced pension income from previous or historical levels, the pension trust has been and remains adequately funded, and no contributions have been required since 1997. As such, these occurrences have had no impact on the Company’s cash flows. Based on stress testing performed by the Company’s actuaries, management does not anticipate the need to make pension contributions until after 2009.

Similar to its pension accounting, SCANA follows SFAS 106, “Employers’ Accounting for Postretirement Benefits Other Than Pensions,” in accounting for its postretirement medical and life insurance benefits. This plan is unfunded, so no assumptions related to rate of return on assets impact the net expense recorded; however, the selection of discount rates can significantly impact the actuarial determination of net expense. SCANA used a discount rate of 6.0% and recorded a net SFAS 106 cost of $18.8 million for 2004. Had the selected discount rate been 5.75%, the expense for 2004 would have been approximately $0.2 million higher.

Asset Retirement Obligations

SFAS 143 provides guidance for recording and disclosing liabilities related to future legally enforceable obligations to retire assets (ARO). SFAS 143 applies to the legal obligation associated with the retirement of long-lived tangible assets that result from their acquisition, construction, development and normal operation. Because such obligation relates solely to the Company’s regulated electric utility, adoption of SFAS 143 had no impact on results of operations. As of January 1, 2003, the Company had recorded an ARO of approximately $111 million, which exceeded the previously recorded reserve for nuclear plant decommissioning of approximately $87 million. At December 31, 2004 such ARO totaled approximately $124 million.

The Company believes that there is legal uncertainty as to the existence of environmental obligations associated with certain of its electric transmission and distribution properties. The Company believes that any ARO related to this type of property would be insignificant and, due to the indeterminate life of the related assets, an ARO could not be reasonably estimated.

OTHER MATTERS

Unconsolidated Special Purpose Entities

Although SCANA invests in securities and business ventures, it does not hold investments in unconsolidated special purpose entities such as those described in SFAS 140, *“Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities,”* or as described in Financial Accounting Standards Board Interpretation 46, *“Consolidation of Variable Interest Entities.”* SCANA does not engage in off-balance sheet financing or similar transactions other than incidental operating leases in the normal course of business, generally for office space, furniture and equipment.

Claims and Litigation

For a description of claims and litigation see Item 3. LEGAL PROCEEDINGS and Note 10 to the consolidated financial statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

All financial instruments held by the Company described below are held for purposes other than trading.

Interest rate risk—The tables below provide information about long-term debt issued by the Company and other financial instruments that are sensitive to changes in interest rates. For debt obligations the tables present principal cash flows and related weighted average interest rates by expected maturity dates. For interest rate swaps, the figures shown reflect notional amounts and related maturities. Fair values for debt and swaps represent quoted market prices.

December 31, 2004 Millions of dollars	Expected Maturity Date 2005	2006	2007	2008	2009	Thereafter	Total	Fair Value
Liabilities								
Long-Term Debt:								
Fixed Rate ($)	193.6	174.4	68.6	158.6	143.6	2,532.8	3,271.6	3,404.5
Average Fixed Interest Rate (%)	7.39	8.50	6.96	8.12	8.21	6.24	6.62	
Variable Rate ($)		200.0					200.0	200.0
Average Variable Interest Rate (%)		2.73					2.73	
Interest Rate Swaps:								
Pay Variable/Receive Fixed ($)	3.20	3.20	28.2	118.2	3.20	119.6	275.6	4.2
Average Pay Interest Rate (%)	5.74	5.74	6.04	4.73	5.74	4.46	4.78	
Average Receive Interest Rate (%)	8.75	8.75	7.11	5.89	8.75	6.45	6.36	

December 31, 2003 Millions of dollars	Expected Maturity Date 2004	2005	2006	2007	2008	Thereafter	Total	Fair Value
Liabilities								
Long-Term Debt:								
Fixed Rate ($)	197.9	193.6	174.4	68.6	158.6	2,540.9	3,334.0	3,384.1
Average Fixed Interest Rate (%)	7.53	7.39	8.50	6.96	8.12	6.27	6.63	
Variable Rate ($)			200.0				200.0	200.0
Average Variable Interest Rate (%)			1.62				1.62	
Interest Rate Swaps:								
Pay Variable/Receive Fixed ($)	57.5	3.20	3.20	28.2	118.2	126.0	336.3	6.33
Average Pay Interest Rate (%)	5.99	4.36	4.36	4.48	3.04	3.01	3.68	
Average Receive Interest Rate (%)	7.70	8.75	8.75	7.11	5.89	6.57	6.61	

While a decrease in interest rates would increase the fair value of debt, it is unlikely that events which would result in a realized loss will occur.

The above table excludes approximately $94 million and $65 million in long-term debt as of December 31, 2004 and 2003, respectively, which amounts do not have a stated interest rate associated with them.

Commodity price risk—The following tables provide information about the Company's financial instruments that are sensitive to changes in natural gas prices. Weighted average settlement prices are per 10,000 mmbtu. Fair values represent quoted market prices.

As of December 31, 2004
Millions of dollars, except weighted average settlement price and strike price

Natural Gas Derivatives:	Expected Maturity in 2005			Expected Maturity in 2006		
	Settlement Price(a)	Contract Amount	Fair Value	Settlement Price(a)	Contract Amount	Fair Value
Futures Contracts:						
Long($)	6.18	43.9	40.4	7.03	0.7	1.0
Short($)	6.16	2.6	2.2	—	—	—
	Strike Price(a)	Contract Amount				
Options:						
Purchased call (long)($)	7.07	65.0				

As of December 31, 2003
Millions of dollars, except weighted average settlement price and strike price

Natural Gas Derivatives:	Expected Maturity in 2004			Expected Maturity in 2005			Expected Maturity in 2006		
	Settlement Price(a)	Contract Amount	Fair Value	Settlement Price(a)	Contract Amount	Fair Value	Settlement Price(a)	Contract Amount	Fair Value
Futures Contracts:									
Long($)	5.74	41.6	46.9	5.05	3.5	4.0	5.12	0.5	0.6
Short($)	6.09	0.7	0.7						
	Strike Price(a)	Contract Amount							
Options:									
Purchased call (long)($)	5.55	43.4							

(a) weighted average

The Company uses derivative instruments to hedge forward purchases and sales of natural gas, which create market risks of different types. See Note 9 to the consolidated financial statements.

The NYMEX futures information above includes those financial positions of Energy Marketing, SCPC and PSNC Energy. Certain derivatives that SCPC utilizes to hedge its gas purchasing activities are recoverable through its weighted average cost of gas calculation. SCPC's tariffs include a purchased gas adjustment (PGA) clause that provides for the recovery of actual gas costs incurred. The offset to the change in fair value of these derivatives is recorded as a current asset or liability. In an October 2004 order, in connection with SCPC's 2004 annual prudency review, the SCPSC determined that SCPC's gas costs, including all hedging activities, were reasonable and prudently incurred during the 12-month review period ended December 31, 2003.

PSNC Energy utilizes NYMEX futures and options to hedge gas purchasing activities. PSNC Energy's tariffs also include a provision for the recovery of actual gas costs incurred. PSNC Energy records transaction fees and any realized gains or losses from derivatives acquired as part of its hedging program in deferred accounts as a regulatory asset or liability for the over or under recovery of gas costs. In a September 2004 order, in connection with PSNC Energy's 2004 annual prudency review, the NCUC determined that PSNC Energy's gas costs, including all hedging transactions, were reasonable and prudently incurred during the 12-month review period ended March 31, 2004.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

SCANA Corporation:

We have audited the accompanying Consolidated Balance Sheets of SCANA Corporation and subsidiaries (the "Company") as of December 31, 2004 and 2003, and the related Consolidated Statements of Operations, Changes in Common Equity and Comprehensive Income (Loss) and of Cash Flows for each of the three years in the period ended December 31, 2004. Our audits also included the financial statement schedule listed in Part IV at Item 15. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of SCANA Corporation and subsidiaries at December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as of December 31, 2004, based on the criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 28, 2005, expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

As discussed in Note 1 to the consolidated financial statements, the Company adopted Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets," effective January 1, 2002.

/s/ Deloitte & Touche LLP
Columbia, South Carolina
February 28, 2005

SCANA Corporation

CONSOLIDATED BALANCE SHEETS

December 31, (Millions of dollars)	2004	2003
Assets		
Utility Plant In Service	$ 8,373	$ 7,438
Accumulated depreciation and amortization	(2,315)	(2,280)
	6,058	5,158
Construction work in progress	432	987
Nuclear fuel, net of accumulated amortization	42	42
Acquisition adjustments	230	230
Utility Plant, Net	6,762	6,417
Nonutility Property and Investments:		
Nonutility property, net of accumulated depreciation of $50 and $39	104	96
Assets held in trust, net—nuclear decommissioning	49	44
Investments	63	178
Nonutility Property and Investments, Net	216	318
Current Assets:		
Cash and cash equivalents	120	117
Receivables, net of allowance for uncollectible accounts of $16 and $16	687	503
Receivables—affiliated companies	19	13
Inventories (at average cost):		
Fuel	191	147
Materials and supplies	70	60
Emission allowances	9	6
Prepayments	49	47
Other	4	—
Total Current Assets	1,149	893
Deferred Debits:		
Environmental	18	20
Pension asset, net	285	270
Other regulatory assets	402	348
Other	164	192
Total Deferred Debits	869	830
Total	$ 8,996	$ 8,458

December 31, (Millions of dollars)	2004	2003
Capitalization and Liabilities		
Shareholders' Investment:		
Common equity	$ 2,451	$ 2,306
Preferred stock (Not subject to purchase or sinking funds)	106	106
Total Shareholders' Investment	2,557	2,412
Preferred Stock, net (Subject to purchase or sinking funds)	9	9
Long-Term Debt, net	3,186	3,225
Total Capitalization	5,752	5,646
Current Liabilities:		
Short-term borrowings	211	195
Current portion of long-term debt	204	202
Accounts payable	381	288
Accounts payable—affiliated companies	18	12
Customer deposits	50	43
Taxes accrued	132	109
Interest accrued	51	55
Dividends declared	43	41
Other	100	78
Total Current Liabilities	1,190	1,023
Deferred Credits:		
Deferred income taxes, net	879	790
Deferred investment tax credits	121	117
Asset retirement obligation—nuclear plant	124	118
Other asset retirement obligations	450	346
Postretirement benefits	142	135
Other regulatory liabilities	199	173
Other	139	110
Total Deferred Credits	2,054	1,789
Commitments and Contingencies (Note 10)	—	—
Total	$ 8,996	$ 8,458

See Notes to Consolidated Financial Statements.

SCANA Corporation

CONSOLIDATED STATEMENTS OF OPERATIONS

For the Years Ended December 31, (Millions of dollars, except per share amounts)	2004	2003	2002
Operating Revenues:			
Electric	$1,688	$1,466	$1,380
Gas—regulated	1,126	1,086	878
Gas—nonregulated	1,071	864	696
Total Operating Revenues	3,885	3,416	2,954
Operating Expenses:			
Fuel used in electric generation	467	334	330
Purchased power	51	64	42
Gas purchased for resale	1,753	1,532	1,199
Other operation and maintenance	608	558	522
Depreciation and amortization	265	238	220
Other taxes	145	139	127
Total Operating Expenses	3,289	2,865	2,440
Operating Income	596	551	514
Other Income (Expense):			
Other income, including allowance for equity funds used during construction of $16, $19 and $23	40	67	71
Gain (loss) on sale of investments and assets	(20)	61	40
Impairment of investments	(27)	(53)	(291)
Total Other Income (Expense)	(7)	75	(180)
Income Before Interest Charges, Income Taxes, Preferred Stock Dividends and Cumulative Effect of Accounting Change	589	626	334
Interest Charges, Net of Allowance for Borrowed Funds Used During Construction of $10, $11 and $12	202	200	199
Income Before Income Taxes, Preferred Stock Dividends and Cumulative Effect of Accounting Change	387	426	135
Income Taxes	123	135	36
Income Before Preferred Stock Dividends and Cumulative Effect of Accounting Change	264	291	99
Dividend Requirement of SCE&G—Obligated Mandatorily Redeemable Preferred Securities	—	2	4
Income Before Cash Dividends on Preferred Stock of Subsidiary and Cumulative Effect of Accounting Change	264	289	95
Cash Dividends on Preferred Stock of Subsidiary (At stated rates)	7	7	7
Income Before Cumulative Effect of Accounting Change	257	282	88
Cumulative Effect of Accounting Change, net of taxes	—	—	(230)
Net Income (Loss)	$ 257	$ 282	$ (142)
Basic and Diluted Earnings (Loss) Per Share of Common Stock:			
Before Cumulative Effect of Accounting Change	$ 2.30	$ 2.54	$ 0.83
Cumulative Effect of Accounting Change, net of taxes	—	—	(2.17)
Basic and Diluted Earnings (Loss) Per Share	$ 2.30	$ 2.54	$ (1.34)
Weighted Average Common Shares Outstanding (millions)	111.6	110.8	106.0

See Notes to Consolidated Financial Statements.

SCANA Corporation

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31, (Millions of dollars)	2004	2003	2002
Cash Flows From Operating Activities:			
Net income (loss)	$ 257	$ 282	$(142)
Adjustments to reconcile net income (loss) to net cash provided from operating activities:			
Cumulative effect of accounting change, net of taxes	—	—	230
Depreciation and amortization	274	249	233
Amortization of nuclear fuel	22	21	20
(Gain) loss on sale of investments	20	(61)	(40)
Impairment of investments	27	53	291
Hedging activities	11	4	42
Allowance for funds used during construction	(26)	(30)	(35)
Changes in certain assets and liabilities:			
(Increase) decrease in receivables	(193)	(27)	(64)
(Increase) decrease in inventories	(57)	24	(1)
(Increase) decrease in prepayments	(2)	4	(19)
(Increase) decrease in pension asset	(15)	(5)	(26)
(Increase) decrease in other regulatory assets	(51)	(38)	3
Increase (decrease) in deferred income taxes, net	74	38	(185)
Increase (decrease) in other regulatory liabilities	45	49	39
Increase (decrease) in postretirement benefits obligations	7	4	9
Increase (decrease) in accounts payable	99	7	61
Increase (decrease) in taxes accrued	23	6	(4)
Increase (decrease) in interest accrued	(4)	3	7
Changes in fuel adjustment clauses	(3)	23	(15)
Changes in other assets	16	(33)	8
Changes in other liabilities	75	37	52
Net Cash Provided From Operating Activities	599	610	464
Cash Flows From Investing Activities:			
Utility property additions and construction expenditures, net of AFC	(498)	(738)	(675)
Proceeds on sale of investments and assets	68	74	568
Nonutility property additions	(23)	(12)	(19)
Investments in affiliates	(19)	(17)	(62)
Net Cash Used For Investing Activities	(472)	(693)	(188)
Cash Flows From Financing Activities:			
Proceeds:			
Issuance of common stock	65	6	149
Issuance of First Mortgage Bonds	—	743	295
Issuance of Pollution Control and Industrial Revenue Bonds	—	36	87
Issuance of notes and loans	136	199	497
Swap settlement	—	—	29
Repayments:			
Mortgage bonds	(100)	(350)	(104)
Notes and loans	(69)	(434)	(915)
Pollution Control Bonds	—	(47)	(62)
Payments of deferred financing costs	—	(25)	—
Retirement of preferred stock and trust preferred securities	—	(50)	(1)
Repurchase of common stock	(4)	(11)	—
Dividends and distributions:			
Common stock	(161)	(151)	(133)
Preferred stock	(7)	(7)	(7)
Short-term borrowings, net	16	(14)	44
Net Cash Used For Financing Activities	(124)	(105)	(121)
Net Increase (Decrease) in Cash and Cash Equivalents	3	(188)	155
Cash and Cash Equivalents, January 1	117	305	150
Cash and Cash Equivalents, December 31	$ 120	$ 117	$ 305
Supplemental Cash Flow Information:			
Cash paid for—Interest (net of capitalized interest of $10, $11 and $12)	$ 206	$ 197	$ 192
—Income taxes	24	77	190
Noncash Investing and Financing Activities:			
Unrealized gain (loss) on securities available for sale, net of tax	(2)	2	87
Columbia Franchise Agreement	—	—	30

See Notes to Consolidated Financial Statements.

SCANA Corporation

CONSOLIDATED STATEMENTS OF CHANGES IN COMMON EQUITY AND COMPREHENSIVE INCOME (LOSS)

	Common Stock		Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
	Shares	Amount			
			(Millions)		
Balance at December 31, 2001	105	$1,043	$1,264	$(113)	$2,194
Comprehensive Income:					
Net loss			(142)		(142)
Unrealized gains on securities, net of taxes $47				87	87
Unrealized gains on hedging activities, net of taxes $15				27	27
Total comprehensive income (loss)			(142)	114	(28)
Issuance of common stock	6	149			149
Dividends declared on common stock			(138)		(138)
Balance as of December 31, 2002	111	$1,192	$ 984	$ 1	$2,177
Comprehensive Income:					
Net Income			282		282
Unrealized gains on securities, net of taxes $1				2	2
Unrealized gains on hedging activities, net of taxes $2				3	3
Total comprehensive income			282	5	287
Issuance of common stock		6			6
Repurchase of common stock		(11)			(11)
Dividends declared on common stock			(153)		(153)
Balance as of December 31, 2003	111	$1,187	$1,113	$ 6	$2,306
Comprehensive Income:					
Net Income			257		257
Unrealized loss on securities, net of taxes $(1)				(2)	(2)
Unrealized loss on hedging activities, net of taxes $(4)				(8)	(8)
Total comprehensive income (loss)			257	(10)	247
Issuance of common stock	2	65			65
Repurchase of common stock		(4)			(4)
Dividends declared on common stock			(163)		(163)
Balance as of December 31, 2004	113	$1,248	$1,207	$ (4)	$2,451

See Notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A. Organization and Principles of Consolidation

SCANA Corporation (SCANA, and together with its consolidated subsidiaries, the Company), a South Carolina corporation, is a registered public utility holding company within the meaning of the Public Utility Holding Company Act of 1935, as amended (PUHCA). The Company, through wholly owned subsidiaries, is engaged predominantly in the generation and sale of electricity to wholesale and retail customers in South Carolina and in the purchase, sale and transportation of natural gas to wholesale and retail customers in South Carolina, North Carolina and Georgia. The Company is also engaged in other energy-related businesses and provides fiber optic communications in South Carolina.

The accompanying Consolidated Financial Statements reflect the accounts of SCANA, the following wholly owned subsidiaries, and one other wholly owned subsidiary in liquidation.

Regulated businesses	Nonregulated businesses
South Carolina Electric & Gas Company (SCE&G)	SCANA Energy Marketing, Inc.
South Carolina Fuel Company, Inc. (Fuel Company)	SCANA Communications, Inc. (SCI)
South Carolina Generating Company, Inc. (GENCO)	ServiceCare, Inc.
Public Service Company of North Carolina, Incorporated (PSNC Energy)	Primesouth, Inc.
South Carolina Pipeline Corporation (SCPC)	SCANA Resources, Inc.
SCG Pipeline, Inc.	SCANA Services, Inc.
	SCANA Corporate Security Services, Inc.

Certain investments are reported using the cost or equity method of accounting, as appropriate. Significant intercompany balances and transactions have been eliminated in consolidation except as permitted by Statement of Financial Accounting Standards (SFAS) 71, *"Accounting for the Effects of Certain Types of Regulation,"* which provides that profits on intercompany sales to regulated affiliates are not eliminated if the sales price is reasonable and the future recovery of the sales price through the rate-making process is probable.

B. Basis of Accounting

The Company accounts for its regulated utility operations, assets and liabilities in accordance with the provisions of SFAS 71, which requires cost-based rate-regulated utilities to recognize in their financial statements certain revenues and expenses in different time periods than do enterprises that are not rate-regulated. As a result, the Company has recorded as of December 31, 2004, approximately

$420 million and $649 million of regulatory assets (including environmental) and liabilities (including other asset retirement obligations), respectively, as shown below.

	December 31, 2004	December 31, 2003
	Millions of dollars	
Accumulated deferred income taxes, net	$ 126	$ 110
Under- (over-) collections—electric fuel and gas cost adjustment clauses, net	41	12
Deferred purchased power costs	26	26
Deferred environmental remediation costs	18	20
Asset retirement obligation—nuclear decommissioning	49	48
Other asset retirement obligations	(450)	(346)
Deferred non-conventional fuel tax benefits, net	(97)	(67)
Storm damage reserve	(33)	(37)
Franchise agreements	58	62
Deferred regional transmission organization costs	14	—
Other	19	21
Total	$(229)	$(151)

Accumulated deferred income tax liabilities arising from utility operations that have not been included in customer rates are recorded as a regulatory asset. Accumulated deferred income tax assets arising from deferred investment tax credits are recorded as a regulatory liability.

Under- (over-) collections—electric fuel and gas adjustment clauses, net represent amounts under-collected from customers pursuant to the fuel adjustment clause (electric customers) or gas cost adjustment clause (gas customers) as approved by the Public Service Commission of South Carolina (SCPSC) or North Carolina Utilities Commission (NCUC) during annual hearings. See Note 1F.

Deferred purchased power costs represent costs that were necessitated by outages at two of SCE&G's base load generating plants in winter 2000-2001. The SCPSC approved recovery of these costs in base rates over a three year period beginning January 2005. See Note 2.

Deferred environmental remediation costs represent costs associated with the assessment and clean-up of manufactured gas plant (MGP) sites currently or formerly owned by the Company. Costs incurred at sites owned by SCE&G are being recovered through rates. Such costs, totaling approximately $10.5 million, are expected to be fully recovered by the end of 2009. A portion of the costs incurred at sites owned by PSNC Energy is also being recovered through rates, and management believes the remaining costs of approximately $6.5 million will be recoverable. Amounts incurred and deferred to date, net of insurance settlements, that are not currently being recovered through gas rates at PSNC Energy are approximately $1.4 million. See Note 2.

Asset retirement obligation (ARO)—nuclear decommissioning represents the regulatory asset associated with the legal obligation to decommission and dismantle V. C. Summer Nuclear Station (Summer Station) as required in SFAS 143, *"Accounting for Asset Retirement Obligations."*

Other asset retirement obligations represent net collections through depreciation rates of estimated costs to be incurred for the future retirement of assets for which no legal retirement obligation exists.

Deferred non-conventional fuel tax benefits represent the deferral of partnership losses and other expenses of approximately $58.7 million, offset by the tax benefits of those losses and expenses and accumulated synthetic fuel tax credits of approximately $155.4 million, associated with SCE&G's two partnerships involved in converting coal to synthetic fuel. Under a plan approved by the SCPSC, any tax credits generated from non-conventional fuel produced by the partnerships and consumed by SCE&G and ultimately passed through to SCE&G, net of partnership losses and other expenses, have been and will be deferred and will be applied to offset the capital costs of constructing the back-up dam at Lake Murray. See Note 2.

The storm damage reserve represents an SCPSC approved reserve account for SCE&G capped at $50 million to be collected through rates. The accumulated storm damage reserve can be applied to offset actual incremental storm damage costs in excess of $2.5 million in a calendar year. For the year ended December 31, 2004, approximately $10.9 million had been drawn from this reserve account.

Franchise agreements represent costs associated with the 30-year electric and gas franchise agreements with the cities of Charleston and Columbia, South Carolina. These amounts are not earning a return, but are being amortized through cost of service over approximately 15 years.

Deferred regional transmission organization costs represent costs incurred by SCE&G in the United States Federal Energy Regulatory Commission (FERC)-mandated formation of GridSouth. The project was suspended in 2002. These amounts are not earning a return, however, in its January 2005 order the SCPSC approved SCE&G's request to amortize these costs over a five-year period. See Note 2.

The SCPSC and the NCUC (collectively, state commissions) have reviewed and approved through specific orders most of the items shown as regulatory assets. Other items represent costs which are not yet approved for recovery by a state commission. In recording these costs as regulatory assets, management believes the costs will be allowable under existing rate-making concepts that are embodied in rate orders received by the Company. However, ultimate recovery is subject to state commission approval. In the future, as a result of deregulation or other changes in the regulatory environment, the Company may no longer meet the criteria for continued application of SFAS 71 and could be required to write off its regulatory assets and liabilities. Such an event could have a material adverse effect on the Company's results of operations, liquidity or financial position in the period the write-off would be recorded.

C. System of Accounts

The accounting records of the Company's regulated subsidiaries are maintained in accordance with the Uniform System of Accounts prescribed by the FERC and as adopted by state commissions.

D. Utility Plant and Major Maintenance

Utility plant is stated substantially at original cost. The costs of additions, renewals and betterments to utility plant, including direct labor, material and indirect charges for engineering, supervision and an allowance for funds used during construction, are added to utility plant accounts. The original cost of utility property retired or otherwise disposed of is removed from utility plant accounts and generally charged to accumulated depreciation. The costs of repairs, replacements and renewals of items of property determined to be less than a unit of property or that do not increase the asset's life or functionality are charged to maintenance expense.

SCE&G, operator of Summer Station, and the South Carolina Public Service Authority (Santee Cooper) are joint owners of Summer Station in the proportions of two-thirds and one-third, respectively. The parties share the operating costs and energy output of the plant in these proportions. Each party, however, provides its own financing. Plant-in-service related to SCE&G's portion of Summer Station was approximately $1.0 billion as of December 31, 2004 and 2003 (including amounts related to ARO). Accumulated depreciation associated with SCE&G's share of Summer Station was approximately $463.7 million and $449.5 million as of December 31, 2004 and 2003, respectively (including amounts related to ARO). SCE&G's share of the direct expenses associated with operating

Summer Station is included in "Other operation and maintenance" expenses and totaled approximately $74.4 million, $74.7 million and $76.4 million for the years ended December 31, 2004, 2003 and 2002, respectively.

Planned major maintenance other than that related to nuclear outages is expensed when incurred. The only major maintenance that is accrued in advance of the time the costs are actually incurred is that related to nuclear refueling outages for which such accounting treatment and rate recovery of expenses accrued thereunder has been approved by the SCPSC. Nuclear outages are scheduled 18 months apart, and SCE&G begins accruing for each successive outage upon completion of the preceding outage. SCE&G is accruing approximately $0.8 million per month from January 2004 through June 2005 for its portion of the outage scheduled to begin in April 2005. Total costs for the 2005 planned outage are estimated to be approximately $22.2 million, of which SCE&G will be responsible for approximately $14.8 million. As of December 31, 2004 and 2003, SCE&G had accrued approximately $9.9 million and $7.5 million, respectively.

E. Allowance for Funds Used During Construction (AFC)

AFC is a noncash item that reflects the period cost of capital devoted to plant under construction. This accounting practice results in the inclusion of, as a component of construction cost, the costs of debt and equity capital dedicated to construction investment. AFC is included in rate base investment and depreciated as a component of plant cost in establishing rates for utility services. The Company's regulated subsidiaries calculated AFC using composite rates of 6.8%, 8.1% and 8.3% for 2004, 2003 and 2002, respectively. These rates do not exceed the maximum allowable rate as calculated under FERC Order No. 561. Interest on nuclear fuel in process is capitalized at the actual interest amount incurred.

F. Revenue Recognition

Revenues are recorded during the accounting period in which services are provided to customers and include estimated amounts for electricity and natural gas delivered, but not yet billed. Unbilled revenues totaled approximately $180.5 million and $134.5 million as of December 31, 2004 and 2003, respectively.

Fuel costs for electric generation are collected through the fuel cost component in retail electric rates. The fuel cost component contained in electric rates is established by the SCPSC during annual fuel cost hearings. Any difference between actual fuel costs and amounts contained in the fuel cost component is deferred and included when determining the fuel cost component during the next annual fuel cost hearing. SCE&G had undercollected through the electric fuel cost component approximately $19.6 million and $1.1 million at December 31, 2004 and 2003, respectively, which amounts are included in other regulatory assets.

Customers subject to the gas cost adjustment clause are billed based on a fixed cost of gas determined by the state commission during annual gas cost recovery hearings. Any difference between actual gas costs and amounts contained in rates is deferred and included when establishing gas costs during the next annual gas cost recovery hearing. At December 31, 2004 and 2003 SCE&G had undercollected approximately $11.1 million and $11.9 million, respectively, which amounts are also included in other regulatory assets. At December 31, 2004 PSNC Energy had undercollected approximately $10 million, which also is included in other regulatory assets. At December 31, 2003 PSNC Energy had overcollected approximately $1.0 million, which is included in other regulatory liabilities.

SCE&G's and PSNC Energy's gas rate schedules for residential, small commercial and small industrial customers include a weather normalization adjustment which minimizes fluctuations in gas revenues due to abnormal weather conditions.

G. Depreciation and Amortization

Provisions for depreciation and amortization are recorded using the straight-line method and are based on the estimated service lives of the various classes of property.

The composite weighted average depreciation rates for utility plant assets were as follows:

	2004	2003	2002
SCE&G	2.99%	3.02%	2.93%
GENCO	2.66%	2.66%	2.66%
SCPC	2.04%	2.13%	2.14%
PSNC Energy	3.87%	4.05%	4.29%
Aggregate of Above	3.04%	3.10%	3.06%

Nuclear fuel amortization, which is included in "Fuel used in electric generation" and recovered through the fuel cost component of SCE&G's rates, is recorded using the units-of-production method. Provisions for amortization of nuclear fuel include amounts necessary to satisfy obligations to the Department of Energy (DOE) under a contract for disposal of spent nuclear fuel. See Note 1H.

The Company considers amounts categorized by FERC as "acquisition adjustments" to be goodwill as defined in SFAS 142, *"Goodwill and Other Intangible Assets,"* and has ceased amortization of such amounts. These amounts are related to acquisition adjustments of approximately $466 million recorded on the books of PSNC Energy (Gas Distribution segment) and approximately $40 million recorded on the books of SCPC (Gas Transmission segment). The Company has no other intangible assets.

In connection with implementation of SFAS 142, effective January 1, 2002, the Company performed a valuation analysis of its investment in SCPC using a discounted cash flows analysis and of PSNC Energy using an independent appraisal. The analysis of the investment in PSNC Energy indicated that the carrying amount of PSNC Energy's acquisition adjustment exceeded its fair value by approximately $230 million or $2.17 per share. The resulting impairment charge is reflected on the statement of operations as the cumulative effect of an accounting change. SFAS 142 requires that an impairment evaluation be performed annually and at the same time each year. Subsequent annual calculations required by SFAS 142 have indicated no need for further write-downs. Should a further write-down be required in the future, such a charge would be treated as an operating expense.

H. Nuclear Decommissioning

SCE&G's two-thirds share of estimated site-specific nuclear decommissioning costs for Summer Station, including the cost of decommissioning plant components not subject to radioactive contamination, totals approximately $357.3 million, stated in 1999 dollars, based on a decommissioning study completed in 2000. Santee Cooper is responsible for decommissioning costs related to its one-third ownership interest in Summer Station. The cost estimate is based on a decommissioning methodology acceptable to the Nuclear Regulatory Commission (NRC) under which the site would be maintained over a period of approximately 60 years in such a manner as to allow for subsequent decontamination that permits release for unrestricted use. SCE&G records its liability for decommissioning cost in deferred credits.

Under SCE&G's method of decommissioning costs, funds collected through rates ($3.2 million in each of 2004, 2003 and 2002) are invested in insurance policies on the lives of certain Company personnel. SCE&G is the beneficiary of these policies. Through these insurance contracts, SCE&G is able to take advantage of income tax benefits and accrue earnings on a tax-deferred basis. Amounts for decommissioning collected through electric rates, insurance proceeds, and interest on proceeds, less expenses, are transferred by SCE&G to an external trust fund. Management intends for the fund, including earnings thereon, to provide for all eventual decommissioning expenditures on an after-tax basis.

In addition to the above, pursuant to the National Energy Policy Act passed by Congress in 1992 and the requirements of the DOE, SCE&G has recorded a liability for its estimated share of the DOE's decontamination and decommissioning obligation. The liability, approximately $1.1 million and $1.5 million at December 31, 2004 and 2003, respectively, has been included in "Long-Term Debt, net." SCE&G is recovering the cost associated with this liability through the fuel cost component of its rates; accordingly, this amount is included in other regulatory assets.

I. Income and Other Taxes

The Company files a consolidated federal income tax return. Under a joint consolidated income tax allocation agreement, each subsidiary's current and deferred tax expense is computed on a stand-alone basis. Deferred tax assets and liabilities are recorded for the tax effects of all significant temporary differences between the book basis and tax basis of assets and liabilities at currently enacted tax rates. Deferred tax assets and liabilities are adjusted for changes in such rates through charges or credits to regulatory assets or liabilities if they are expected to be recovered from, or passed through to, customers of the Company's regulated subsidiaries; otherwise, they are charged or credited to income tax expense.

The Company records excise taxes billed and collected, as well as local franchise and similar taxes, as liabilities until they are remitted to the respective taxing authority. As such, no excise taxes are included in revenues or expenses in the statements of operations.

J. Debt Premium, Discount and Expense, Unamortized Loss on Reacquired Debt

Long-term debt premium and discount are recorded in long-term debt and are amortized as components of Interest Charges over the terms of the respective debt issues. Other issuance expense and gains or losses on reacquired debt that is refinanced are recorded in other deferred debits or credits and amortized over the term of the replacement debt.

K. Environmental

The Company maintains an environmental assessment program to identify and evaluate current and former sites that could require environmental cleanup. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and clean up each site. These estimates are refined as additional information becomes available; therefore, actual expenditures could differ significantly from the original estimates. Amounts estimated and accrued to date for site assessments and cleanup relate solely to regulated operations. Such amounts are recorded in deferred debits and are amortized with recovery provided through rates.

L. Cash and Cash Equivalents

The Company considers temporary cash investments having original maturities of three months or less at time of purchase to be cash equivalents. These cash equivalents are generally in the form of commercial paper, certificates of deposit, repurchase agreements, treasury bills and notes.

M. Commodity Derivatives

The Company records derivatives contracts at their fair value in accordance with SFAS 133, *"Accounting for Derivative Instruments and Hedging Activities,"* as amended, and adjusts fair value each reporting period. The Company determines fair value of most of the energy-related derivatives contracts using quotations from markets where they are actively traded and quoted. For other derivatives contracts the Company uses published market surveys and, in certain cases, independent parties to obtain quotes concerning fair value. Market quotes tend to be more plentiful for those derivatives contracts maturing in two years or less. The Company's derivatives contracts do not extend beyond two years. See Note 9.

SCPC's tariffs include a purchased gas adjustment (PGA) clause that provides for the recovery of actual gas costs incurred. The SCPSC has ruled that the results of SCPC's hedging activities are to be included in the PGA. As such, costs of related derivatives that SCPC utilizes to hedge its gas purchasing activities are recoverable through its weighted average cost of gas calculation. The offset to the change in fair value of these derivatives is recorded as a current asset or liability. PSNC Energy's tariffs include a provision for the recovery of actual gas costs incurred. PSNC Energy records transaction fees and any realized gains or losses from derivatives acquired as part of its hedging program in deferred accounts as a regulatory asset or liability for the over or under recovery of gas costs.

N. New Accounting Standards

SFAS 123 (revised 2004), *"Share-Based Payment,"* was issued in December 2004 and will require compensation costs related to share-based payment transactions to be recognized in the financial statements. With limited exceptions, the amount of compensation cost will be measured based on the grant-date fair value of the instruments issued. Compensation cost will be recognized over the period that an employee provides service in exchange for the award. SFAS 123(R) replaces SFAS 123, *"Accounting for Stock-Based Compensation"* and supersedes APB 25, *"Accounting for Stock Issued to Employees."* The Company will adopt SFAS 123(R) in the third quarter of 2005. The Company does not expect that the initial adoption of SFAS 123(R) will have a material impact on the Company's results of operations, cash flows or financial position.

SFAS 153, *"Exchanges of Nonmonetary Assets,"* was issued in December 2004 and amends APB 29, *"Accounting for Nonmonetary Transactions."* SFAS 153 makes a general exception from fair value measurement for exchanges of nonmonetary assets that do not have commercial substance. A nonmonetary exchange has commercial substance if the future cash flows of the entity are expected to change significantly as a result of the exchange. SFAS 153 applies prospectively to nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. The Company does not expect that the initial adoption of SFAS 153 will have a material impact on the Company's results of operations, cash flows or financial position.

At the June 30—July 1, 2004 meeting of the Emerging Issues Task Force (EITF), the EITF reached a consensus on Issue No. 02-14, *"Whether an Investor Should Apply the Equity Method of Accounting to Investments Other Than Common Stock."* The EITF determined that an investor should apply the equity method of accounting when it has an investment in common stock or an investment that is in-substance common stock, as defined, provided that the investor has the ability to exercise significant influence over the operating and financial policies of the investee. This consensus must be applied in reporting periods beginning after September 15, 2004. The Company's initial adoption of the guidance in the fourth quarter of 2004 had no impact on the Company's results of operations, cash flows or financial position.

At the March 2004 and November 2003 EITF meetings, the EITF reached consensus on certain matters related to Issue No. 03-01, *"The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments."* EITF Issue No. 03-01 requires that certain disclosures be made related to investments that are impaired at the balance sheet date but for which an other-than-temporary impairment has not been recognized. Guidance for evaluating whether an investment is other-than-temporarily impaired is also provided in the consensus. The impairment guidance applies to reporting periods beginning after June 15, 2004. The disclosure guidance is effective for annual financial statements for fiscal years ending after December 15, 2003. The Company's initial adoption of the impairment guidance on July 1, 2004 had no impact on the Company's results of operations, cash flows or financial position.

O. Equity Compensation Plan

Under the SCANA Corporation Long-Term Equity Compensation Plan (the Plan), certain employees and non-employee directors may receive incentive and nonqualified stock options and other forms of equity compensation. The Company accounts for this equity-based compensation using the intrinsic value method under APB 25, *"Accounting for Stock Issued to Employees,"* and related interpretations. In addition, the Company has adopted the disclosure provisions of SFAS 123, *"Accounting for Stock-Based Compensation,"* and SFAS 148 *"Accounting for Stock-Based Compensation—Transition and Disclosure."* As discussed in Note 1N, the Company will adopt SFAS 123(R) in the third quarter of 2005.

All options have been granted with exercise prices equal to the fair market value of the Company's stock on the respective grant dates since the Plan's inception; therefore, no compensation expense has been recognized in connection with such grants. If the Company had determined compensation expense for the issuance of options based on the fair value method described in SFAS 123, pro forma net income (loss) and earnings (loss) per share would have been as presented below:

	2004	2003	2002
Net income (loss)—as reported (millions)	$257.1	$282.0	$(141.7)
Net income (loss)—pro forma (millions)	256.0	280.3	(143.3)
Basic and diluted earnings (loss) per share—as reported	2.30	2.54	(1.34)
Basic and diluted earnings (loss) per share—pro forma	2.29	2.52	(1.35)

The Company also grants other forms of equity based compensation to certain employees. The value of such awards is recognized as compensation expense under APB 25.

P. Earnings Per Share

Earnings (loss) per share amounts have been computed in accordance with SFAS 128, *"Earnings Per Share."* Under SFAS 128, basic earnings per share are computed by dividing net income by the weighted average number of common shares outstanding for the period. Diluted earnings per share are computed by dividing net income by the weighted average number of shares of common stock outstanding during the period after giving effect to securities considered to be dilutive potential common stock. The Company uses the treasury stock method in determining total dilutive potential common stock. The Company has no securities that would have an antidilutive effect on earnings per share.

Q. Affiliated Transactions

SCE&G holds two equity-method investments in partnerships involved in converting coal to non-conventional fuel. SCE&G had recorded as receivables from these affiliated companies approximately $18.6 million and $13.4 million at December 31, 2004 and 2003, respectively. SCE&G had recorded as payables to these affiliated companies approximately $17.8 million and $12.2 million at December 31, 2004 and 2003, respectively. SCE&G purchased approximately $190.6 million, $145.8 million and $117.2 million of synthetic fuel from these affiliated companies in 2004, 2003 and 2002, respectively.

R. Reclassifications

Certain amounts from prior periods have been reclassified to conform with the presentation adopted for 2004.

S. Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amount of revenues and expenses during the reporting period. Actual results could differ from those estimates.

2. RATE AND OTHER REGULATORY MATTERS

South Carolina Electric & Gas Company (SCE&G)

Electric

In a January 2005 order the SCPSC granted SCE&G a composite increase in retail electric rates of approximately 2.89%, designed to produce additional annual revenues of approximately $41.4 million based on a test year calculation. The SCPSC lowered SCE&G's return on common equity from 12.45% to a range of between 10.4% and 11.4%, with rates to be set at 10.7%. The new rates became effective in January 2005. As part of its order, the SCPSC approved SCE&G's recovery of construction and operating costs for SCE&G's new Jasper County Electric Generating Station, recovery of costs of mandatory environmental upgrades primarily related to Federal Clean Air Act regulations and the application of current and anticipated net synthetic fuel tax credits to offset the cost of constructing the back-up dam at Lake Murray. The SCPSC also approved recovery over a five-year period of SCE&G's approximately $14 million of costs incurred in the formation of the GridSouth Regional Transmission Organization and recovery through base rates over three years of approximately $25.6 million of purchased power costs that were previously deferred. As a part of its order, the SCPSC extended through 2010 its approval of the accelerated capital recovery plan for SCE&G's Cope Generating Station. Under the plan, based on the level of revenues and operating expenses, SCE&G may increase depreciation of its Cope Generating Station in excess of amounts that would be recorded based upon currently approved depreciation rates, not to exceed $36 million annually, without additional approval of the SCPSC. Any unused portion of the $36 million in any given year may be carried forward for possible use in the following year.

In January 2003 the SCPSC granted SCE&G a composite increase in retail electric rates of approximately 5.8% designed to produce additional annual revenues of approximately $70.7 million based on a test year calculation. The SCPSC authorized a return on common equity of 12.45%. The rates and authorized return were effective for service rendered on and after February 1, 2003 until January 2005.

SCE&G's rates are established using a cost of fuel component approved by the SCPSC which may be modified periodically to reflect changes in the price of fuel purchased by SCE&G. SCE&G's cost of fuel component in effect during 2004 and 2003 was as follows:

Rate Per KWh	Effective Date
$1.722	January 2003
$1.678	February 2003-April 2004
$1.821	May-December 2004

Gas

SCE&G's rates are established using a cost of gas component approved by the SCPSC which may be modified periodically to reflect changes in the price of natural gas purchased by SCE&G. SCE&G's cost of gas component in effect during 2004 and 2003 was as follows:

Rate Per Therm	Effective Date
$.728	January-February 2003
$.928	March-October 2003
$.877	November 2003-October 2004
$.903	November-December 2004

The SCPSC allows SCE&G to recover through a billing surcharge to its gas customers the costs of environmental cleanup at the sites of former MGPs. The billing surcharge is subject to annual review and provides for the recovery of substantially all actual and projected site assessment and cleanup costs and environmental claims settlements for SCE&G's gas operations that had previously been recorded in deferred debits. In October 2003, as a result of the annual review, the SCPSC approved SCE&G's request to reduce the billing surcharge from 3.0 cents per therm to 0.8 cents per therm, which is intended to provide for the recovery, prior to the end of the year 2009, of the balance remaining at December 31, 2004 of $10.5 million.

Public Service Company of North Carolina, Incorporated (PSNC Energy)

PSNC Energy's rates are established using a benchmark cost of gas approved by the NCUC, which may be modified periodically to reflect changes in the market price of natural gas. PSNC Energy revises its tariffs with the NCUC as necessary to track these changes and accounts for any over- or under-collections of the delivered cost of gas in its deferred accounts for subsequent rate consideration. The NCUC reviews PSNC Energy's gas purchasing practices annually.

PSNC Energy's benchmark cost of gas in effect during 2004 and 2003 was as follows:

Rate Per Therm	Effective Date
$.460	January-February 2003
$.595	March 2003
$.725	April-November 2003
$.600	December 2003-September 2004
$.675	October-November 2004
$.825	December 2004

On February 3, 2005 the NCUC approved PSNC Energy's request to decrease the benchmark cost of gas from $.825 per therm to $.725 per therm for service rendered on and after February 1, 2005.

On January 21, 2005 the NCUC authorized PSNC Energy to defer for subsequent rate consideration certain expenses incurred to comply with the U. S. Department of Transportation's Pipeline Integrity Management requirements. This accounting treatment is effective November 1, 2004.

In September 2004, in connection with PSNC Energy's 2004 Annual Prudence Review, the NCUC determined that PSNC Energy's gas costs, including all hedging transactions, were reasonable and prudently incurred during the 12-month review period ended March 31, 2004. The NCUC also authorized new rate decrements to refund over-collections of certain gas costs included in PSNC Energy's deferred accounts, effective March 1, 2004.

A state expansion fund, established by the North Carolina General Assembly and funded by refunds from PSNC Energy's interstate pipeline transporters, provides financing for expansion into areas that otherwise would not be economically feasible to serve. In June 2000 the NCUC approved

PSNC Energy's requests for disbursement of up to $28.4 million from PSNC Energy's expansion fund to extend natural gas service to Madison, Jackson and Swain Counties in western North Carolina. The final phase of this project was completed and placed in service in April 2004 at a total cost of approximately $30.3 million.

In December 1999 the NCUC issued an order approving SCANA's acquisition of PSNC Energy. As specified in the order, PSNC Energy agreed to a moratorium on general rate increases until after August 2005. General rate relief can be obtained during this period to recover costs associated with materially adverse governmental actions and force majeure events.

South Carolina Pipeline Corporation

SCPC's purchased gas adjustment for cost recovery and gas purchasing policies are reviewed annually by the SCPSC. In an October 2004 order, the SCPSC found that for the period January 2003 through December 2003 SCPC's gas purchasing policies and practices were prudent and SCPC properly adhered to the gas cost recovery provisions of its gas tariff.

3. EMPLOYEE BENEFIT PLANS AND EQUITY COMPENSATION PLAN

Pension and Other Postretirement Benefit Plans

The Company sponsors a noncontributory defined benefit pension plan, covering substantially all permanent employees. The Company's policy has been to fund the plan to the extent permitted by applicable federal income tax regulations as determined by an independent actuary.

Effective July 1, 2000 the Company's pension plan was amended to provide a cash balance formula. With certain exceptions employees were allowed to either remain under the final average pay formula or elect the cash balance formula. Under the final average pay formula, benefits are based on years of credited service and the employee's average annual base earnings received during the last three years of employment. For employees electing the cash balance formula, the monthly benefit earned under the final average pay formula at July 1, 2000 was converted to a lump sum amount and increased by transition credits for eligible employees. This opening balance increases going forward as a result of compensation credits and interest credits.

In addition to pension benefits, the Company provides certain unfunded postretirement health care and life insurance benefits to active and retired employees. Retirees share in a portion of their medical care cost. The Company provides life insurance benefits to retirees at no charge. The costs of postretirement benefits other than pensions are accrued during the years the employees render the services necessary to be eligible for these benefits.

The measurement date used to determine pension and other postretirement benefit obligations is December 31. Information regarding the benefit obligations and the funding thereof is presented below.

Changes in Benefit Obligation

Data related to the changes in the projected benefit obligation for retirement benefits and the accumulated benefit obligation for other postretirement benefits are presented below.

	Retirement Benefits		Other Postretirement Benefits	
	2004	2003	2004	2003
	Millions of dollars			
Benefit obligation, January 1	$619.9	$595.6	$188.4	$183.4
Service cost	11.1	9.5	3.3	2.7
Interest cost	37.4	36.7	11.4	11.4
Plan participants' contributions	—	—	1.1	0.8
Plan amendments	8.0	—	4.7	—
Actuarial loss	24.1	7.6	1.2	4.3
Benefits paid	(31.0)	(29.5)	(12.6)	(14.2)
Benefit obligation, December 31	$669.5	$619.9	$197.5	$188.4

The accumulated benefit obligation for retirement benefits at the end of 2004 and 2003 was $635.8 million and $589.8 million, respectively. These accumulated retirement benefit obligations differ from the projected retirement benefit obligations above in that they reflect no assumptions about future compensation levels.

Significant assumptions used to determine the above benefit obligations are as follows:

	2004	2003
Annual discount rate used to determine benefit obligations	5.75%	6.00%
Assumed annual rate of future salary increases for projected benefit obligation	4.00%	4.00%

A 9.0% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2004. The rate was assumed to decrease gradually to 5.0% for 2011 and to remain at that level thereafter. The effects of a one percentage point increase or decrease on accumulated other postretirement benefit obligation for health care benefits are as follows:

	1% Increase	1% Decrease
	Millions of dollars	
Effect on postretirement benefit obligation	$4.0	$(3.5)

In December 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the "Act") was enacted. The Act established a prescription drug benefit under Medicare, known as "Medicare Part D," and a federal subsidy to sponsors of retiree health care benefit plans that provide a prescription drug benefit that is at least actuarially equivalent to Medicare Part D. The Company anticipates that benefits provided to some groups of plan participants will be actuarially equivalent to Medicare Part D and therefore will entitle the Company to a federal subsidy.

In May 2004, the FASB issued FASB Staff Position No. FAS 106-2, *"Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act"* ("FSP 106-2"). FSP 106-2 provides definitive guidance on the recognition of the effects of the Act and related disclosure requirements for employers that sponsor prescription drug benefit plans for retirees. In the quarter beginning July 1, 2004 the Company adopted FSP 106-2. The expected subsidy reduced the accumulated postretirement benefit obligation (APBO) as of July 1, 2004 by $3.7 million, and net periodic cost for 2004 by $0.2 million, as compared to the amount calculated without considering the effects of the subsidy.

Changes in Plan Assets

	Retirement Benefits	
	2004	2003
	Millions of dollars	
Fair value of plan assets, January 1	$787.7	$666.9
Actual return on plan assets	90.0	150.3
Benefits paid	(31.0)	(29.5)
Fair value of plan assets, December 31	$846.7	$787.7

At the end of 2004 and 2003, the fair value of plan assets for the pension plan exceeded both the projected benefit obligation and the accumulated benefit obligation discussed above. Since the accumulated benefit obligation is less than the fair value of plan assets, there is no adjustment to other comprehensive income.

Funded Status of Plans

	Retirement Benefits		Other Postretirement Benefits	
	2004	2003	2004	2003
	Millions of dollars			
Funded status, December 31	$177.2	$167.8	$(197.5)	$(188.4)
Unrecognized actuarial loss	28.2	23.1	44.2	45.0
Unrecognized prior service cost	78.3	76.8	6.4	2.9
Unrecognized net transition obligation	1.4	2.3	5.0	5.9
Net asset (liability) recognized in consolidated balance sheet	$285.1	$270.0	$(141.9)	$(134.6)

In connection with the joint ownership of Summer Station, as of December 31, 2004 and 2003 the Company recorded within deferred credits a $9.7 million and $9.3 million obligation, respectively, to Santee Cooper, representing an estimate of the net pension asset attributable to the Company's contributions to the pension plan that were recovered through billings to Santee Cooper for its one-third portion of shared costs. As of December 31, 2004 and 2003, the Company also recorded a $6.8 million and $6.5 million receivable, respectively, from Santee Cooper, representing an estimate of its portion of the unfunded net postretirement benefit obligation.

Expected Cash Flows

The total benefits expected to be paid from the pension plan or from the Company's assets for the pension and other postretirement benefits plans, respectively, are as follows:

Expected Benefit Payments Millions of dollars	Pension Benefits	Other Postretirement Benefits*
2005	$ 41.8	$13.4
2006	44.2	13.9
2007	44.7	14.0
2008	49.2	13.9
2009	49.9	14.0
2010-2014	287.0	73.9

* Net of participant contributions

Net Periodic Cost

As allowed by SFAS 87 and SFAS 106, the Company records net periodic benefit cost (income) utilizing beginning of the year assumptions. Disclosures required for these plans under SFAS 132, "Employer's Disclosures about Pensions and Other Postretirement Benefits," are set forth in the following tables:

Components of Net Periodic Benefit Cost (Income)

	Retirement Benefits			Other Postretirement Benefits		
	2004	2003	2002	2004	2003	2002
	Millions of dollars					
Service cost	$ 11.1	$ 9.5	$ 9.0	$ 3.3	$ 2.7	$ 3.1
Interest cost	37.4	36.7	39.8	11.4	11.4	12.4
Expected return on assets	(71.0)	(59.9)	(77.6)	n/a	n/a	n/a
Prior service cost amortization	6.6	6.3	6.3	1.4	0.9	0.9
Actuarial (gain) loss	—	1.6	(4.1)	1.9	1.5	1.1
Transition amount amortization	0.8	0.8	0.8	0.8	0.8	0.8
Net periodic benefit (income) cost	$(15.1)	$ (5.0)	$(25.8)	$18.8	$17.3	$18.3

Significant Assumptions Used in Determining Net Periodic Benefit Cost (Income)

	Retirement Benefits			Other Postretirement Benefits		
	2004	2003	2002	2004	2003	2002
Discount rate	6.00%	6.50%	7.50%	6.00%	6.50%	7.50%
Expected return on plan assets	9.25%	9.25%	9.50%	n/a	n/a	n/a
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
Health care cost trend rate	n/a	n/a	n/a	9.50%	10.00%	8.50%
Ultimate health care cost trend rate	n/a	n/a	n/a	5.00%	5.00%	5.00%
Year achieved	n/a	n/a	n/a	2011	2011	2009
Measurement date	Jan 1	Jan 1	Jan 1	Jan 1	Jan 1	Jan 1

The effect of a one-percentage-point increase or decrease in the assumed health care cost trend rate on total service and interest cost is less than $250,000.

Pension Plan Contributions

While the investment performance over the 2000-2002 period and the recent decline in discount rates have significantly reduced the level of pension income, the pension trust has been and remains adequately funded. No contributions have been required since 1997, and the Company does not anticipate making contributions to the funded pension plan in 2005. As such, these declines in pension income have had no impact on the Company's cash flows.

Pension Plan Asset Allocations

The Company's pension plan asset allocation at December 31, 2004 and 2003 and the target allocation for 2005 are as follows:

	Target Allocation	Percentage of Plan Assets At December 31	
Asset Category	**2005**	**2004**	**2003**
Equity Securities	70%	72%	71%
Debt Securities	30%	28%	29%

The assets of the pension plan are invested in accordance with the objectives of (1) fully funding the actuarial accrued liability for the pension plan, (2) maximizing return within reasonable and prudent levels of risk in order to minimize contributions, and (3) maintaining sufficient liquidity to meet benefit payment obligations on a timely basis. These objectives have been based on a ten-year investment horizon, so that interim fluctuations should be viewed with appropriate perspective. The pension plan operates with several risk and control procedures, including ongoing reviews of liabilities, investment objectives, investment managers and performance expectations. Transactions involving certain types of investments are prohibited. Equity securities held by the pension plan during the above periods did not include SCANA common stock.

In developing the expected long-term rate of return assumptions, management continually evaluates the pension plan's historical cumulative actual returns over several periods, all of which returns have been in excess of related broad indices. Management anticipates that the pension plan's investment managers will continue to generate long-term returns of at least 9.25%. The expected long-term rate of return of 9.25% assumes an asset allocation of 70% with equity managers and 30% with fixed income managers. Management regularly reviews such allocations and periodically rebalances the portfolio to the targeted allocation when considered appropriate.

Long-Term Equity Compensation Plan

The Long-Term Equity Compensation Plan provides for grants of incentive and nonqualified stock options, stock appreciation rights, restricted stock, performance shares and performance units to certain key employees and non-employee directors. The plan currently authorizes the issuance of up to five million shares of the Company's common stock, no more than one million of which may be granted in the form of restricted stock.

A summary of activity related to grants of nonqualified stock options follows:

	Number of Options	Weighted Average Exercise Price
Outstanding—December 31, 2001	802,281	$27.11
Granted	1,116,638	27.56
Exercised	(103,677)	27.12
Forfeited	(97,332)	27.38
Outstanding—December 31, 2002	1,717,910	27.39
Granted	—	n/a
Exercised	(203,052)	27.41
Forfeited	(21,173)	27.50
Outstanding—December 31, 2003	1,493,685	27.39
Granted	—	n/a
Exercised	(751,997)	26.28
Forfeited	(11,241)	27.52
Outstanding—December 31, 2004	730,447	27.49

One-third of the options vest on each anniversary of the date of grant until full vesting occurs. The options expire ten years after the grant date. Information about outstanding and exercisable options as of December 31, 2004 follows:

	Options Outstanding			Options Exercisable	
Range Of Exercise Prices	Number of Options	Weighted Average Remaining Contractual Life (in years)	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price
$25.50-$29.60	730,447	6.5	$27.49	388,487	$27.42

At December 31, 2003 and 2002 exercisable options totaled 648,392 at a weighted average exercise price of $27.19 and 274,306 at a weighted average exercise price of $26.91, respectively.

For purposes of the pro forma information presented in Note 1O, the weighted average fair value at grant date (the value at grant date of the right to purchase stock at a fixed price for an extended time period) for options granted in 2002 was $4.67. This fair value was estimated using the Black-Scholes option pricing model and weighted average assumptions for expected life of options (7 years), risk free interest rate (4.64%), volatility of underlying stock (21%) and dividend yield of underlying stock (4.4%). No options have been granted since 2002.

The Company also grants other forms of equity based compensation to certain employees. These awards consist of hypothetical share grants which vest and become payable upon the attainment of specified performance metrics, and compensation is recorded under APB 25. These awards may be settled in shares of Company stock or in cash at the Company's determination. Total expense recorded for these awards was approximately $13.2 million, $9.4 million and $1.5 million in 2004, 2003 and 2002, respectively.

4. LONG-TERM DEBT

Long-term debt by type with related weighted average interest rates and maturities is as follows:

	Weighted-Average Rate	Year Due	December 31, 2004	December 31, 2003
			Millions of dollars	
Medium-Term Notes (unsecured)(a)	5.77%	2005-2012	$1,040	$1,090
First Mortgage Bonds (secured)	6.25%	2005-2033	1,700	1,800
First & Refunding Mortgage Bonds (secured)	9.00%	2006	131	131
GENCO Notes (secured)	6.02%	2011-2024	130	34
Industrial and Pollution Control Bonds	5.24%	2012-2032	156	156
Senior Debentures(b)	7.53%	2005-2026	126	133
Fair value of interest rate swaps(c)			32	38
Other		2005-2013	94	65
Total debt			3,409	3,447
Current maturities of long-term debt			(204)	(202)
Unamortized Discount			(19)	(20)
Total long-term debt, net			$3,186	$3,225

(a) Includes $200.0 million of variable interest debt and $250.0 million of fixed rate debt hedged by variable rate swaps.

(b) Includes $25.6 million of fixed rate debt hedged by variable interest rate swaps.

(c) Includes $4.2 million related to the fair market value of current swaps and $27.9 million representing unamortized payments received to terminate previous swaps. See discussion at Note 9.

The annual amounts of long-term debt maturities and sinking fund requirements for the years 2005 through 2009 are summarized as follows:

Year	Amount	Year	Amount
	(Millions of dollars)		
2005	$200	2008	$165
2006	380	2009	150
2007	75		

Approximately $35.5 million of the long-term debt maturing in 2005 relates to a sinking fund requirement, which may be satisfied by either deposit and cancellation of bonds issued upon the basis of property additions or bond retirement credits, or by deposit of cash with the Trustee.

In 2004 SCE&G borrowed $35.4 million under an agreement with the South Carolina Transportation Infrastructure Bank (the Bank) and the South Carolina Department of Transportation (SCDOT) that allows SCE&G to borrow funds from the Bank to construct a roadbed for SCDOT in connection with the Lake Murray Dam remediation project. The loan agreement provides for interest-free borrowings of up to $59 million with such borrowings being repaid over ten years from the initial borrowing. At December 31, 2004 SCE&G had $32.5 million outstanding under the agreement.

Substantially all of SCE&G's and GENCO's utility plant is pledged as collateral in connection with long-term debt. The Company is in compliance with all debt covenants.

5. LINES OF CREDIT AND SHORT-TERM BORROWINGS

Details of lines of credit and short-term borrowings at December 31, 2004 and 2003, are as follows:

	2004	2003
	Millions of dollars	
Lines of credit (total and unused)		
Committed		
Short-term	$ 100	$ 625
Long-term	650	75
Uncommitted	113(1)	113(1)
Commercial paper outstanding (270 or fewer days):		
SCE&G	$ 122	$ 94
Weighted average interest rate	2.39%	1.15%
Fuel Company	$ 31	$ 46
Weighted average interest rate	2.44%	1.15%
PSNC Energy	$ 58	$ 55
Weighted average interest rate	2.47%	1.17%
Total	$ 211	$ 195
Weighted average interest rate	2.42%	1.16%

(1) Lines of credit that either SCANA or SCE&G may use.

The Company pays fees to banks as compensation for maintaining committed lines of credit.

Nuclear and fossil fuel inventories and sulfur dioxide emission allowances are financed through the issuance by Fuel Company of short-term commercial paper. All commercial paper borrowings are supported by five-year revolving credit facilities which expire on June 15, 2009. The committed credit facilities provide for a maximum of $750 million to be outstanding at any time.

6. COMMON EQUITY

The Company's Restated Articles of Incorporation do not limit the dividends that may be paid on its common stock. However, the Restated Articles of Incorporation of SCE&G contain provisions that, under certain circumstances, which the Company considers to be remote, could limit the payment of cash dividends on its common stock. In addition, with respect to hydroelectric projects, the Federal Power Act requires the appropriation of a portion of certain earnings therefrom. At December 31, 2004 approximately $48 million of retained earnings were restricted by this requirement as to payment of cash dividends on SCE&G's common stock.

Cash dividends on common stock were declared during 2004, 2003 and 2002 at an annual rate per share of $1.46, $1.38 and $1.30, respectively.

The accumulated balances related to each component of other comprehensive income (loss) were as follows:

	Unrealized gains (losses) on securities	Cash flow hedging activities	Accumulated Other Comprehensive Income (loss)
	Millions of dollars		
Balance, December 31, 2001	$(87)	$(26)	$(113)
Other comprehensive income	87	27	114
Balance, December 31, 2002	—	1	1
Other comprehensive income	2	3	5
Balance, December 31, 2003	2	4	6
Other comprehensive income	(2)	(8)	(10)
Balance, December 31, 2004	$ —	$ (4)	$ (4)

During 2004, $0.7 million was reclassified from unrealized gains and $12.5 million was reclassified from unrealized losses on securities into net income (loss) as a result of the sale of the Company's investments in ITC^DeltaCom and the impairment and subsequent sale of the Company's investment in Knology. See Note 9. The Company also recognized a gain of $6.4 million, net of taxes, as a result of qualifying cash flow hedges whose hedged transactions occurred during the year ended December 31, 2004.

During 2003, no unrealized gains (losses) on securities were reclassified into net income (loss). The Company recognized a gain of $3.9 million, net of tax, as a result of qualifying cash flow hedges whose hedged transactions occurred during the year ended December 31, 2003.

During 2002, $87 million was reclassified from unrealized gains (losses) on securities into net income (loss) as a result of the recording of an impairment in the value of the Deutsche Telekom AG (DTAG) investment. The Company also recognized a loss of approximately $20.6 million, net of tax, as a result of qualifying cash flow hedges whose hedged transactions occurred during the year ended December 31, 2002.

7. PREFERRED STOCK

Retirements under sinking fund requirements are at par values. The aggregate of the annual amounts of purchase or sinking fund requirements for preferred stock for the years 2005 through 2009 is $2.7 million. The call premium of the respective series of preferred stock in no case exceeds the amount of the annual dividend. At December 31, 2004 SCE&G had shares of preferred stock authorized and available for issuance as follows:

Par Value	Authorized	Available for Issuance
$100	1,000,000	—
$ 50	609,688	300,000
$ 25	2,000,000	2,000,000

Preferred Stock (Not Subject to purchase or sinking funds)

For each of the three years ended December 31, 2004 SCE&G had outstanding 1,000,000 shares of 6.52% $100 par and 125,209 shares of 5.00% $50 par Cumulative Preferred Stock (not subject to purchase or sinking funds).

Preferred Stock (Subject to purchase or sinking funds)

Changes in "Total Preferred Stock (Subject to purchase or sinking funds)" during 2004, 2003 and 2002 are summarized as follows:

	Series			
	4.50%, 4.60% (A) & 5.125%	4.60% (B) & 6.00%		Millions
Redemption Price	$51.00	$50.50	Total Shares	of Dollars
Balance at December 31, 2001	88,449	121,035	209,484	$10.5
Shares Redeemed—$50 par value	(4,600)	(4,911)	(9,511)	(0.5)
Balance at December 31, 2002	83,849	116,124	199,973	10.0
Shares Redeemed—$50 par value	(2,815)	(3,563)	(6,378)	(0.3)
Balance at December 31, 2003	81,034	112,561	193,595	9.7
Shares Redeemed—$50 par value	(2,516)	(6,600)	(9,116)	(0.5)
Balance at December 31, 2004	78,518	105,961	184,479	$ 9.2

In 1997 SCE&G Trust I (the "Trust"), a wholly owned subsidiary of SCE&G, issued $50 million of 7.55% Trust Preferred Securities, Series A. In 2003 SCE&G effected the redemption of those securities.

8. INCOME TAXES

Total income tax expense attributable to income (before the cumulative effect of an accounting change) for 2004, 2003 and 2002 is as follows:

	2004	2003	2002
	Millions of dollars		
Current taxes:			
Federal	$ (6.4)	$ 63.1	$ 174.6
State	(5.2)	12.2	9.0
Foreign	—	—	1.0
Total current taxes	$(11.6)	$ 75.3	$ 184.6
Deferred taxes, net:			
Federal	84.5	24.6	(178.5)
State	5.4	0.3	0.8
Total deferred taxes	89.9	24.9	(177.7)
Investment tax credits:			
Deferred—State	10.0	5.0	5.0
Amortization of amounts deferred—State	(2.1)	(1.8)	(1.7)
Amortization of amounts deferred—Federal	(4.0)	(4.0)	(4.0)
Total investment tax credits	3.9	(0.8)	(0.7)
Non-conventional fuel tax credits:			
Deferred—Federal	40.5	35.7	29.8
Total income tax expense	$122.7	$135.1	$ 36.0

The difference between actual income tax expense and that amount calculated from the application of the statutory federal income tax rate (35% for 2004, 2003 and 2002) to pre-tax income (before the cumulative effect of an accounting change) is reconciled as follows:

	2004	2003	2002
	Millions of dollars		
Income before cumulative effect of accounting change	$257.1	$282.0	$ 87.9
Income tax expense	122.7	135.1	36.0
Preferred stock dividends	7.3	9.1	11.2
Total pre-tax income	$387.1	$426.2	$135.1
Income taxes on above at statutory federal income tax rate	$135.5	$149.2	$ 47.3
Increases (decreases) attributed to:			
State income taxes (less federal income tax effect)	5.3	10.2	8.5
Allowance for equity funds used during construction	(5.5)	(6.7)	(7.9)
Deductible dividends—Stock Purchase Savings Plan	(5.5)	(4.9)	(4.5)
Amortization of federal investment tax credits	(4.0)	(4.0)	(4.0)
Other differences, net	(3.1)	(8.7)	(3.4)
Total income tax expense	$122.7	$135.1	$ 36.0

The tax effects of significant temporary differences comprising the Company's net deferred tax liability of $884.5 million at December 31, 2004 and $790.9 million at December 31, 2003 (see Note 1I) are as follows:

	2004	2003
	Millions of dollars	
Deferred tax assets:		
Nondeductible reserves	$ 84.5	$ 70.6
Unamortized investment tax credits	60.8	59.9
Deferred compensation	24.0	22.3
Federal alternative minimum tax credit carryforward	12.3	—
Investments in equity securities	1.1	43.3
Other	34.3	40.5
Total deferred tax assets	217.0	236.6
Deferred tax liabilities:		
Property, plant and equipment	937.9	889.2
Pension plan benefit income	101.4	94.5
Deferred fuel costs	20.3	13.6
Other	41.9	30.2
Total deferred tax liabilities	1,101.5	1,027.5
Net deferred tax liability	$ 884.5	$ 790.9

The Internal Revenue Service has completed and closed examinations of the Company's consolidated federal income tax returns through tax years ending in 2000. The IRS has also closed the examination of S. C. Coaltech No. 1 L.P., a synthetic fuel partnership in which the Company has an interest, for the 2000 tax year, resulting in that return being accepted as filed. The Company continues to believe that all of its synthetic fuel tax credits have been properly claimed.

9. FINANCIAL INSTRUMENTS

The carrying amounts and estimated fair values of the Company's financial instruments at December 31, 2004 and 2003 are as follows:

	2004		2003	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	Millions of dollars			
Assets:				
Cash and cash equivalents	$ 120.0	$ 120.0	$ 116.8	$ 116.8
Investments	63.1	63.1	177.2	178.1
Liabilities:				
Short-term borrowings	210.7	210.7	195.3	195.3
Long-term debt	3,389.5	3,699.9	3,427.4	3,654.8
Preferred stock (subject to purchase or sinking funds)	9.2	8.5	9.7	8.8

The following methods and assumptions were used to estimate the fair value of financial instruments:

- Cash and cash equivalents, which may include commercial paper, certificates of deposit, repurchase agreements, treasury bills and notes, are valued at their carrying amount.
- Fair values of investments and long-term debt are based on quoted market prices of the instruments or similar instruments. For debt instruments for which no quoted market prices are available, fair values are based on net present value calculations. For investments for which the fair value is not readily determinable, fair value is considered to approximate carrying value. Carrying values reflect the fair values of interest rate swaps based on settlement values obtained from counterparties. Early settlement of long-term debt may not be possible or may not be considered prudent.
- Short-term borrowings are valued at their carrying amount.
- The fair value of preferred stock (subject to purchase or sinking funds) is estimated using market prices.
- Potential taxes and other expenses that would be incurred in an actual sale or settlement have not been considered.

Investments

Certain of SCANA's subsidiaries hold investments in marketable securities, some of which are subject to SFAS 115, *"Accounting for Certain Investments in Debt and Equity Securities,"* mark-to-market accounting and some of which are considered cost basis investments for which determination of fair value historically has been considered impracticable. Equity holdings subject to SFAS 115 are categorized as "available for sale" and are carried at quoted market prices, with any unrealized gains and losses credited or charged to other comprehensive income (loss) within common equity on the Company's balance sheet. When indicated, and in accordance with its stated accounting policy, the Company performs periodic assessments of whether any decline in the value of these securities to amounts below the Company's cost basis is other than temporary. When other than temporary declines occur, write-downs are recorded through operations, and new (lower) cost bases are established. The Company also holds investments in several partnerships and joint ventures which are accounted for using the equity method.

Telecommunications Investments

At December 31, 2004 SCANA Communications Holdings, Inc. (SCH), a wholly owned, indirect subsidiary of the Company, held 6.2 million non-voting common shares of Magnolia Holding Company LLC (Magnolia Holding), a Company that holds ownership interests in several southeastern communications companies and other investments. SCH's investment at December 31, 2004 totaled $1.3 million.

In December 2004 SCH sold its investments in ITC^DeltaCom, Inc. (ITC^DeltaCom) and Knology, Inc. (Knology) resulting in losses of $13.9 million, net of taxes. In the third quarter 2004, SCH recorded an impairment of its investment in Knology totaling $15.0 million, net of taxes.

In August 2003, Magnolia Holding distributed its holdings in Knology preferred stock to Magnolia Holding's members. As a result, SCH's basis in Magnolia Holding was reduced by, and SCH's basis in Knology was increased by, approximately $6.2 million. During 2003, SCH recorded impairment losses associated with its Knology investment totaling $34.6 million, net of taxes.

In May 2003 the Company's investment in ITC Holding Company, Inc. was sold. The transaction resulted in the receipt of net after-tax cash proceeds of approximately $48 million and the receipt of the above investment interest in a newly formed entity, Magnolia Holding. A book gain, net of tax, of approximately $39 million was realized upon this transaction.

Derivatives

SFAS 133, *"Accounting for Derivative Instruments and Hedging Activities,"* as amended, requires the Company to recognize all derivative instruments as either assets or liabilities in the statement of financial position and to measure those instruments at fair value. SFAS 133 further provides that changes in the fair value of derivative instruments are either recognized in earnings or reported as a component of other comprehensive income (loss), depending upon the intended use of the derivative and the resulting designation. The fair value of derivative instruments is determined by reference to quoted market prices of listed contracts, published quotations or quotations from independent parties.

Policies and procedures and risk limits are established to control the level of market, credit, liquidity and operational and administrative risks assumed by the Company. SCANA's Board of Directors has delegated to a Risk Management Committee the authority to set risk limits, establish policies and procedures for risk management and measurement, and oversee and review the risk management process and infrastructure. The Risk Management Committee, which is comprised of certain officers, including the Company's Risk Management Officer and senior officers, apprises the Board of Directors with regard to the management of risk and brings to the Board's attention any areas of concern. Written policies define the physical and financial transactions that are approved, as well as the authorization requirements and limits for transactions.

Commodities

The Company uses derivative instruments to hedge forward purchases of natural gas, which create market risks of different types. Instruments designated as cash flow hedges are used to hedge risks associated with fixed price obligations in a volatile market and risks associated with price differentials at different delivery locations. The basic types of financial instruments utilized are exchange-traded instruments, such as New York Mercantile Exchange (NYMEX) futures contracts or options, and over-the-counter instruments such as swaps, which are typically offered by energy and financial institutions.

The Company recognized gains (losses) of approximately $6.4 million, $3.9 million and $(20.6) million, net of tax, as a result of qualifying cash flow hedges whose hedged transactions occurred during the years ended December 31, 2004, 2003 and 2002, respectively. These amounts were recorded in cost of gas. The Company estimates that most of the December 31, 2004 unrealized loss balance of $3.4 million, net of tax, will be reclassified from accumulated other comprehensive income (loss) to earnings in 2005 as an increase to gas cost if market prices remain at current levels. As of December 31, 2004, all of the Company's cash flow hedges will settle by their terms before the end of 2006.

PSNC Energy hedges gas purchasing activities using NYMEX futures and options. PSNC Energy's tariffs include a provision for the recovery of actual gas costs incurred. PSNC Energy records transaction fees and any realized gains or losses from derivatives acquired as part of its hedging program in deferred accounts as a regulatory asset or liability for the over or under recovery of gas costs.

SCPC's tariffs include a purchased gas adjustment (PGA) clause that provides for the recovery of actual gas costs incurred. The SCPSC has ruled that the results of SCPC's hedging activities are to be included in the PGA. As such, costs of related derivatives that SCPC utilizes to hedge its gas purchasing activities are recoverable through its weighted average cost of gas calculation. The offset to the change in fair value of these derivatives is recorded as a current asset or liability.

Interest Rates

The Company uses interest rate swap agreements to manage interest rate risk. These swaps provide for the Company to pay variable and receive fixed rate interest payments and are designated as fair value hedges of certain debt instruments. The Company may terminate a swap and may replace it with a new swap also designated as a fair value hedge.

Payments received upon termination of a swap are recorded as basis adjustments to long-term debt and are amortized as reductions to interest expense over the term of the underlying debt. The fair value of the swaps is recorded within other deferred debits on the balance sheet. The resulting credits serve to reflect the hedged long-term debt at its fair value. Periodic receipts or payments related to the swaps are credited or charged to interest expense as incurred.

The Company received a payment to terminate a swap totaling $29.3 million in 2002. This amount is being amortized over the ten-year term of the underlying debt it formerly hedged. At December 31, 2004 the estimated fair value of the Company's swaps totaled $4.2 million related to combined notional amounts of $275.6 million.

In anticipation of the issuance of debt, the Company uses interest rate lock or similar agreements to manage interest rate risk. Payments received or made upon termination of such agreements are recorded within other deferred debits on the balance sheet and are amortized to interest expense over the term of the underlying debt. In connection with the issuance of First Mortgage Bonds in May 2003, the Company paid approximately $11.9 million upon the termination of a treasury lock agreement. In connection with the issuance of First Mortgage Bonds in December 2003, the Company paid approximately $3.5 million upon the termination of a forward starting interest rate swap.

10. COMMITMENTS AND CONTINGENCIES

A. Lake Murray Dam Reinforcement

In 2001 SCE&G began construction to reinforce its Lake Murray Dam in order to comply with new federal safety standards mandated by FERC. Construction for the project and related activities is expected to cost approximately $275 million (excluding AFC) and be completed in 2005. Costs incurred through December 31, 2004 totaled approximately $240 million.

B. Nuclear Insurance

The Price-Anderson Indemnification Act (the Act) deals with public liability for a nuclear incident. Though the Act expired in 2003, existing licensees, such as the Company, are "grandfathered" under the Act until such time as it is renewed. The Act establishes the liability limit for third-party claims associated with any nuclear incident at $10.5 billion. Each reactor licensee is currently liable for up to $100.6 million per reactor owned for each nuclear incident occurring at any reactor in the United States, provided that not more than $10 million of the liability per reactor would be assessed per year. SCE&G's maximum assessment, based on its two-thirds ownership of Summer Station, would be approximately $67.1 million per incident, but not more than $6.7 million per year.

SCE&G currently maintains policies (for itself and on behalf of Santee Cooper) with Nuclear Electric Insurance Limited. The policies, covering the nuclear facility for property damage, excess property damage and outage costs, permit retrospective assessments under certain conditions to cover insurer's losses. Based on the current annual premium, SCE&G's portion of the retrospective premium assessment would not exceed $15.8 million.

To the extent that insurable claims for property damage, decontamination, repair and replacement and other costs and expenses arising from a nuclear incident at Summer Station exceed the policy limits of insurance, or to the extent such insurance becomes unavailable in the future, and to the extent that SCE&G's rates would not recover the cost of any purchased replacement power, SCE&G will retain the risk of loss as a self-insurer. SCE&G has no reason to anticipate a serious nuclear incident at Summer Station. If such an incident were to occur, it would have a material adverse impact on the Company's results of operations, cash flows and financial position.

C. Environmental

South Carolina Electric & Gas Company

At SCE&G, site assessment and cleanup costs are deferred and amortized with recovery provided through rates. Deferred amounts, net of amounts previously recovered through rates and insurance settlements, totaled $10.5 million at December 31, 2004. The deferral includes the estimated costs associated with the following matters.

SCE&G owns a decommissioned MGP site in the Calhoun Park area of Charleston, South Carolina. The site is currently being remediated for contamination. SCE&G anticipates that the remaining remediation activities will be completed by the end of 2005, with certain monitoring and other activities continuing until 2010. As of December 31, 2004, SCE&G has spent approximately $20.5 million to remediate the Calhoun Park site, and expects to spend an additional $1.3 million. In addition, SCE&G is party to certain claims for cost and damages from this site, for which claims the National Park Service of the Department of the Interior made an initial demand for payment of approximately $9 million. Any costs arising from these matters are expected to be recoverable through rates under South Carolina regulatory processes.

SCE&G owns three other decommissioned MGP sites in South Carolina which contain residues of by-product chemicals. One of the sites has been remediated and will undergo routine monitoring until released by DHEC. The other two sites are currently being investigated under work plans approved by DHEC. SCE&G anticipates that major remediation activities for the three sites will be completed in 2010. As of December 31, 2004, SCE&G has spent approximately $4 million related to these three sites, and expects to spend an additional $4 million.

Public Service Company of North Carolina, Incorporated

PSNC Energy is responsible for environmental cleanup at five sites in North Carolina on which MGP residuals are present or suspected. PSNC Energy's actual remediation costs for these sites will depend on a number of factors, such as actual site conditions, third-party claims and recoveries from other PRPs. PSNC Energy has recorded a liability and associated regulatory asset of approximately $6.5 million, which reflects the estimated remaining liability at December 31, 2004. Amounts incurred and deferred to date, net of insurance settlements, that are not currently being recovered through gas rates are approximately $1.4 million. Management believes that all MGP cleanup costs incurred will be recoverable through gas rates.

D. Franchise Agreements

See Note 1B for a discussion of the electric and gas franchise agreements between SCE&G and the cities of Columbia and Charleston.

E. Claims and Litigation

In 1999 an unsuccessful bidder for the purchase of certain of SCANA's propane gas assets filed suit against SCANA in Circuit Court, seeking unspecified damages. The suit alleged the existence of a contract for the sale of assets to the plaintiff and various causes of action associated with that contract. On October 21, 2004, the jury issued an adverse verdict on this matter against SCANA for four causes of action for damages totaling $48 million. Post-verdict motions were heard in November 2004 and January 2005. It is SCANA's interpretation that the damages awarded with respect to certain causes of action are overlapping. Therefore, it is SCANA's belief that a reasonably possible estimate of the total damages based on the amounts awarded by the jury will be in the range of $18—$36 million. However, SCANA believes that the verdict was inconsistent with the facts presented and applicable law and intends to appeal any adverse judgment by the Circuit Court. Based on the current status of this matter, and in accordance with generally accepted accounting principles, SCANA recorded a pre-tax charge to earnings in the third quarter of 2004 of $18 million, $11 million after-tax, or 10 cents per share, which is SCANA's reasonable estimate of the minimum loss that is probable if the final judgment is consistent with the jury verdict. The charge and associated liability are reported in Other Income (Expense) and Current Liabilities-Other in the financial statements. It is expected that the final judgment will be rendered in 2005 but that appeals may continue for a longer period. The Company is also defending another claim for $2.7 million for reimbursement of legal fees and expenses under an indemnification and hold harmless agreement in the contract of sale. A bench trial on the indemnification was held on January 14, 2005, and a ruling is expected in March.

On August 21, 2003, SCE&G was served as a co-defendant in a purported class action lawsuit styled as Collins v. Duke Energy Corporation, Progress Energy Services Company, and SCE&G, in South Carolina's Circuit Court of Common Pleas for the Fifth Judicial Circuit. The plaintiffs are seeking damages for the alleged improper use of electric transmission and distribution easements but have not asserted a dollar amount for their claims. Specifically, the plaintiffs contend that the licensing of attachments on electric utility poles, towers and other facilities to non-utility third parties or telecommunication companies for other than the electric utilities' internal use along the electric transmission line right-of-way constitutes a trespass. The Company is confident of the propriety of SCE&G's actions and intends to mount a vigorous defense. The Company further believes that the resolution of these claims will not have a material adverse impact on its results of operations, cash flows or financial condition.

On May 17, 2004, the Company was served with a purported class action lawsuit styled as Douglas E. Gressette, individually and on behalf of other persons similarly situated, v. South Carolina Electric & Gas Company and SCANA Corporation. The case was filed in South Carolina's Circuit Court of Common Pleas for the Ninth Judicial Circuit. The plaintiff alleges the Company made improper use of certain easements and rights-of-way by allowing fiber optic communication lines and/or wireless communication apparatuses to transmit communications other than the Company's electricity-related internal communications. The plaintiff asserts causes of action for unjust enrichment, trespass, injunction and declaratory judgment. The plaintiff did not assert a specific dollar amount for the claims. The Company believes its actions are consistent with governing law and the applicable documents granting easements and rights-of-way. The Company intends to mount a vigorous defense and believes that the resolution of these claims will not have a material adverse impact on its results of operations, cash flows or financial condition.

A complaint was filed on October 22, 2003 against SCE&G by the State of South Carolina alleging that SCE&G violated the Unfair Trade Practices Act by charging municipal franchise fees to some customers residing outside a municipality's limits. The complaint alleged that SCE&G failed to obey, observe or comply with the lawful order of the SCPSC by charging franchise fees to those not residing within a municipality. The complaint sought restitution to all affected customers and penalties up to $5,000 for each separate violation. The State of South Carolina v. SCE&G has been settled by an agreement between the parties, and the settlement has been approved by the court. The allegations are also the subject of a purported class action lawsuit filed in December 2003, against Duke Energy Corporation, Progress Energy Services Company and SCE&G (styled Edwards v. SCE&G). Duke Energy and Progress Energy have been voluntarily dismissed from the Edwards lawsuit. The Company believes that the resolution of these actions will not have a material adverse impact on its results of operations, cash flows or financial condition. In addition, SCE&G filed a petition with the SCPSC on October 23, 2003 pursuant to S. C. Code Ann. R.103-836. The petition requests that the SCPSC exercise its jurisdiction to investigate the operation of the municipal franchise fee collection requirements applicable to SCE&G's electric and gas service, to approve SCE&G's efforts to correct any past franchise fee billing errors, to adopt improvements in the system which will reduce such errors in the future, and to adopt any regulation that the SCPSC deems just and proper to regulate the franchise fee collection process.

The Company is also engaged in various other claims and litigation incidental to its business operations which management anticipates will be resolved without material loss to the Company.

F. Operating Lease Commitments

The Company is obligated under various operating leases with respect to office space, furniture and equipment. Leases expire at various dates through 2013. Rent expense totaled approximately $11.8 million, $12.4 million and $11.5 million in 2004, 2003 and 2002, respectively. Future minimum rental payments under such leases are as follows:

	Millions
2005	$14.8
2006	12.5
2007	10.7
2008	9.8
2009	8.1
Thereafter	0.3
	$56.2

At December 31, 2004 minimum rentals to be received under noncancelable subleases with remaining lease terms in excess of one year totaled approximately $8.6 million.

G. Purchase Commitments

The Company is obligated for purchase commitments that expire at various dates through 2034. Purchase commitments expensed under forward contracts for natural gas purchases, gas transportation capacity agreements, coal supply contracts, nuclear fuel contracts, construction projects and other commitments totaled $1,592.3 million, $1,156.5 million and $665.6 million in 2004, 2003 and 2002, respectively. Amounts expensed under coal contracts are based on a weighted average cost which include spot market purchases and freight expenditures. Coal spot market purchases represented 13%-14.5% of coal expense for the years 2002-2004. Future payments under such purchase commitments are as follows:

	Millions
2005	$1,256.7
2006	816.7
2007	571.4
2008	491.9
2009	420.0
Thereafter	3,459.5
	$7,016.2

Forward contracts for natural gas purchases include customary "make-whole" or default provisions, but are not considered to be "take-or-pay" contracts.

In addition, included in purchase commitments are customary purchase orders under which the Company has the option to utilize certain vendors without the obligation to do so. The Company may terminate such commitments without penalty.

11. SEGMENT OF BUSINESS INFORMATION

The Company's reportable segments are described below. The accounting policies of the segments are the same as those described in the summary of significant accounting policies. The Company records intersegment sales and transfers of electricity and gas based on rates established by the appropriate regulatory authority. Nonregulated sales and transfers are recorded at current market prices.

Electric Operations is primarily engaged in the generation, transmission and distribution of electricity, and is regulated by the SCPSC and FERC.

Gas Distribution, comprised of the local distribution operations of SCE&G and PSNC Energy, is engaged in the purchase and sale, primarily at retail, of natural gas. SCE&G and PSNC Energy are regulated by the SCPSC and the NCUC, respectively. Gas Transmission is comprised of SCPC, which is engaged in the purchase, transmission and sale of natural gas on a wholesale basis to distribution companies (including SCE&G), and to industrial customers in South Carolina, and is regulated by the SCPSC.

Retail Gas Marketing markets natural gas in Georgia and is regulated as a marketer by the Georgia Public Service Commission. Energy Marketing markets electricity and natural gas to industrial, large commercial and wholesale customers, primarily in the Southeast.

The Company's regulated reportable segments share a similar regulatory environment and, in some cases, overlapping service areas. However, Electric Operations' product differs from the other segments, as does its generation process and method of distribution. The gas segments differ from each other primarily based on the class of customers each serves and the marketing strategies resulting from those differences. The marketing segments differ from each other primarily based on their respective markets and customer type.

Disclosure of Reportable Segments (Millions)

2004	Electric Operations	Gas Distribution	Gas Transmission	Gas Retail Marketing	Energy Marketing	All Other	Adjustments/ Eliminations	Consolidated Total
Customer Revenue	$1,688	$ 914	$212	$552	$520	$ 58	$ (59)	$3,885
Intersegment Revenue	4	—	339	—	77	304	(724)	—
Operating Income	550	67	19	n/a	n/a	n/a	(40)	596
Interest Expense	10	21	5	3	—	—	163	202
Depreciation & Amortization	208	47	7	2	—	12	(11)	265
Income Tax Expense (Benefit)	(2)	15	5	18	(1)	(8)	96	123
Net Income (Loss)	n/a	n/a	n/a	29	(2)	(39)	269	257
Segment Assets	5,365	1,540	362	201	91	498	939	8,996
Expenditures for Assets	389	86	10	—	3	16	17	521
Deferred Tax Assets	3	8	5	4	3	2	(25)	—

2003	Electric Operations	Gas Distribution	Gas Transmission	Gas Retail Marketing	Energy Marketing	All Other	Adjustments/ Eliminations	Consolidated Total
Customer Revenue	$1,466	$ 870	$217	$448	$416	$ 56	$ (57)	$3,416
Intersegment Revenue	5	(1)	303	—	—	277	(584)	—
Operating Income	426	77	16	n/a	n/a	1	31	551
Interest Expense	7	21	5	4	—	1	162	200
Depreciation & Amortization	183	47	7	1	—	9	(9)	238
Income Tax Expense (Benefit)	2	19	4	12	(1)	9	90	135
Net Income (Loss)	n/a	n/a	n/a	20	(1)	4	259	282
Segment Assets	5,038	1,477	334	133	53	699	724	8,458
Expenditures for Assets	655	68	18	—	—	35	(26)	750
Deferred Tax Assets	3	6	5	6	2	44	(66)	—

2002	Electric Operations	Gas Distribution	Gas Transmission	Gas Retail Marketing	Energy Marketing	All Other	Adjustments/ Eliminations	Consolidated Total
Customer Revenue	$1,380	$ 653	$225	$380	$316	$ 69	$ (69)	$2,954
Intersegment Revenue	5	1	254	—	—	289	(549)	—
Operating Income	417	69	6	n/a	n/a	—	22	514
Interest Expense	8	21	5	3	1	12	149	199
Depreciation & Amortization	166	47	6	—	1	7	(7)	220
Income Tax Expense (Benefit)	3	13	—	6	(1)	(81)	96	36
Net Income (Loss)	n/a	n/a	n/a	14	—	(170)	14	(142)
Segment Assets	4,511	1,406	321	128	53	691	964	8,074
Expenditures for Assets	617	68	17	—	—	15	(23)	694
Deferred Tax Assets	6	6	6	5	2	26	(51)	—

Revenues and assets from segments below the quantitative thresholds are attributable to ten other direct and indirect wholly owned subsidiaries of the Company. These subsidiaries conduct nonregulated operations in energy-related and telecommunications industries. None of these subsidiaries met the quantitative thresholds for determining reportable segments during any period reported.

Management uses operating income to measure segment profitability for SCE&G and other regulated operations and evaluates utility plant, net, for segments attributable to SCE&G. As a result, SCE&G does not allocate interest charges, income tax expense or assets other than utility plant to its segments. For nonregulated operations management uses net income (loss) as the measure of segment profitability and evaluates total assets for financial position. Interest income is not reported by segment and is not material. In accordance with SFAS 109, the Company's deferred tax assets are netted with deferred tax liabilities for reporting purposes. For 2002 adjustments to Net Income and Income Tax Expense (Benefit) include the cumulative effect of the accounting change. See Note 1G.

The Consolidated Financial Statements report operating revenues which are comprised of the energy-related reportable segments. Revenues from non-reportable segments are included in Other Income. Therefore the adjustments to total revenue remove revenues from non-reportable segments. Adjustments to Net Income consist of SCE&G's unallocated net income.

Segment Assets include utility plant, net for SCE&G's Electric Operations and Gas Distribution, and all assets for PSNC Energy and the remaining segments. As a result, adjustments to assets include non-utility plant and non-fixed assets for SCE&G.

Adjustments to Interest Expense, Income Tax Expense (Benefit) and Expenditures for Assets include primarily the totals from SCANA or SCE&G that are not allocated to the segments. Interest Expense is also adjusted to eliminate inter-affiliate charges. Adjustments to Depreciation and Amortization consist of non-reportable segment expenses, which are not included in the depreciation and amortization reported on a consolidated basis. Expenditures for Assets are adjusted for AFC. Deferred Tax Assets are adjusted to net them against deferred tax liabilities on a consolidated basis.

12. QUARTERLY FINANCIAL DATA (UNAUDITED)

2004 Millions, except per share amounts	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Annual
Total operating revenues	$1,136	$846	$857	$1,046	$3,885
Operating income	194	123	161	118	596
Net income	101	60	54	42	257
Basic and diluted earnings per share	.91	.54	.48	.37	2.30

2003 Millions, except per share amounts	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Annual
Total operating revenues	$1,069	$726	$751	$870	$3,416
Operating income	168	100	150	133	551
Net income	84	74	84	40	282
Basic and diluted earnings per share	.75	.67	.76	.36	2.54

SOUTH CAROLINA ELECTRIC & GAS COMPANY

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Statements included in this discussion and analysis of South Carolina Electric & Gas Company (SCE&G, and together with its consolidated affiliates, the Company) (or elsewhere in this annual report) which are not statements of historical fact are intended to be, and are hereby identified as, "forward-looking statements" for purposes of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Readers are cautioned that any such forward-looking statements are not guarantees of future performance and involve a number of risks and uncertainties, and that actual results could differ materially from those indicated by such forward-looking statements. Important factors that could cause actual results to differ materially from those indicated by such forward-looking statements include, but are not limited to, the following: (1) that the information is of a preliminary nature and may be subject to further and/or continuing review and adjustment, (2) regulatory actions or changes in the utility regulatory environment, (3) current and future litigation, (4) changes in the economy, especially in the Company's service territory, (5) the impact of competition from other energy suppliers, including competition from alternate fuels in industrial interruptible markets, (6) growth opportunities, (7) the results of financing efforts, (8) changes in the Company's accounting policies, (9) weather conditions, especially in areas served by the Company, (10) performance of SCANA Corporation's (SCANA) pension plan assets and the impact on the Company's results of operations, (11) inflation, (12) changes in environmental regulations and (13) the other risks and uncertainties described from time to time in the Company's periodic reports filed with the SEC, including those risks described in Item 1 under Risk Factors. The Company disclaims any obligation to update any forward-looking statements.

OVERVIEW

SCE&G is a regulated public utility engaged in the generation, transmission, distribution and sale of electricity and in the purchase and sale, primarily at retail, of natural gas. SCE&G's business is subject to seasonal fluctuations. Generally, sales of electricity are higher during the summer and winter months because of air-conditioning and heating requirements, and sales of natural gas are greater in the winter months due to heating requirements. SCE&G's electric service area extends into 24 counties covering more than 15,000 square miles in the central, southern and southwestern portions of South Carolina. The service area for natural gas encompasses all or part of 34 of the 46 counties in South Carolina and covers more than 22,000 square miles.

Electric Operations

The electric operations segment is comprised of the electric operations of SCE&G, GENCO and Fuel Company, and is primarily engaged in the generation, transmission and distribution of electricity in South Carolina. At December 31, 2004 SCE&G provided electricity to over 580,000 customers in an area of approximately 15,000 square miles. GENCO owns and operates a coal-fired generation station and sells electricity solely to SCE&G. Fuel Company acquires, owns and provides financing for SCE&G's nuclear fuel, fossil fuel and emission allowance requirements. Both GENCO and Fuel Company are consolidated with SCE&G for financial reporting purposes.

Operating results for electric operations are primarily driven by customer demand for electricity, the ability to control costs and rates allowed to be charged to customers. Embedded in the rates charged to customers is an allowed regulatory return on equity. The allowed return on equity for SCE&G was 12.45% in 2004. In January 2005, as a result of an electric rate case, the allowed return on equity was lowered to a range of 10.4% to 11.4%, with rates to be set at 10.7%. See further discussion at Liquidity and Capital Resources. Demand for electricity is primarily affected by weather, customer growth and the economy.

Legislative and regulatory initiatives also could significantly impact the results of operations and cash flows for the electric operations segment. In South Carolina the state legislature is not actively pursuing electric restructuring. However, both houses of the U.S. Congress introduced energy legislation in the 2003-2004 legislative sessions, but failed to reach a compromise on certain key issues unrelated to utilities. Energy legislation is expected to be reintroduced in 2005. It is anticipated that such legislation would include provisions that would repeal PUHCA and transfer additional regulatory authority to FERC. Provisions in the legislation would likely impose reliability standards for high-voltage transmission systems. New legislation may also impose stringent requirements on power plants to reduce emissions of sulfur dioxide, nitrogen oxides (NOx) and mercury. It is also possible that new initiatives will be introduced to reduce carbon dioxide emissions. The Company cannot predict whether such legislation will be enacted, and if it is, the conditions it would impose on utilities.

In April 2004 the joint U.S.-Canada Power System Outage Task Force issued its "Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations" (Blackout Report). The Blackout Report contains 46 recommendations that, if implemented, the Task Force believes would improve reliability of North America's interconnected bulk power system (the grid). Full implementation of the Blackout Report's recommendations would require a number of actions by legislative, regulatory and industry participants. However, the Blackout Report asserts as its single most important recommendation that the U.S. Congress should enact tougher reliability standards. It is anticipated that any reliability legislation, if passed, would make reliability standards mandatory and enforceable with penalties for non-compliance and would strengthen the role of FERC.

Regardless of the outcome of any legislative activity, FERC is expected to proceed with regulatory initiatives that, if enacted, could significantly change the country's existing regulatory framework governing transmission, open access and energy markets and would attempt, in large measure, to standardize the national energy market and attempt to disaggregate the remaining vertically integrated utilities. In July 2002 FERC issued a Notice of Proposed Rulemaking on Standard Market Design (SMD) which FERC supplemented with the issuance of a "white paper" in April 2003. If implemented, the proposed rule could have a significant impact on SCE&G's access to or cost of power for its native load customers and on SCE&G's marketing of power outside its service territory. The Company is currently evaluating FERC's action to determine potential effects on SCE&G's operations. Additional directives from FERC are expected.

The North American Electric Reliability Council (NERC) also is expected to continue its initiatives to develop, establish and enforce additional standards for the grid. To that end, NERC is working closely with FERC to implement stronger reliability standards among NERC's voluntary membership. SCE&G, along with other NERC members, is also working closely with NERC in these efforts. Such initiatives could be significantly influenced by any reliability legislation enacted by Congress. The Company cannot predict whether Congress will enact reliability legislation or the extent to which the other recommendations contained in the Blackout Report will be implemented. Any action by Congress or initiatives by FERC or NERC could significantly impact SCE&G's access to or cost of power for its native load customers and SCE&G's marketing of power outside its service territory.

Gas Distribution

The gas distribution segment is comprised of the local distribution operations of SCE&G and is primarily engaged in the purchase and sale, primarily at retail, of natural gas in portions of South Carolina. At December 31, 2004 this segment provided natural gas to approximately 282,000 customers.

Operating results for gas distribution are primarily influenced by customer demand for natural gas, the ability to control costs and allowed rates to be charged to customers. Embedded in the rates charged to customers is an allowed regulatory return on equity, which in 2004 was 12.25%. Demand for natural gas is primarily affected by weather, customer growth, the economy and, for commercial and industrial customers, the availability and price of alternate fuels. Natural gas competes with electricity, propane and heating oil to serve the heating and, to a lesser extent, other household energy needs of residential and small commercial customers. This competition is generally based on price and convenience. Large commercial and industrial customers often have the ability to switch from natural gas to an alternate fuel, such as propane or fuel oil. Natural gas competes with these alternate fuels based on price. As a result, any significant disparity between supply and demand, either of natural gas or of alternate fuels, and due either to production or delivery disruptions or other factors, will affect price and impact SCE&G's ability to retain large commercial and industrial customers.

RESULTS OF OPERATIONS

Net Income

Net income and the percent change from the previous year for the years 2004, 2003 and 2002 were as follows:

	2004	2003	2002
	Millions of dollars		
Net income	$232.5	$220.5	$219.6
Percent increase (decrease) in net income	5.5%	0.4%	(1.0)%

- 2004 vs 2003 Net income increased primarily due to higher electric margins of $62.2 million, partially offset by lower gas margins of $4.6 million, increased operations and maintenance expenses of $17.4 million, higher depreciation and amortization expense of $15.3 million, higher taxes other than income of $3.3 million and lower AFC of $3.5 million.
- 2003 vs 2002 Net income increased slightly primarily due to higher electric margins of $36.8 million, higher gas margins of $2.6 million, reduction of preferred dividend requirements of $0.9 million and other of $1.3 million, partially offset by higher operations and maintenance expenses of $15.9 million (including $7.1 due to lower pension income), higher depreciation and amortization expense of $10.9 million, higher property taxes of $7.2 million and higher interest expense of $6.7 million.

Pension Income

Pension income was recorded on SCE&G's financial statements as follows:

	2004	2003	2002
	Millions of dollars		
Income Statement Impact:			
(Component of) reduction in employee benefit costs	$ 4.2	$(1.0)	$10.5
Other income	11.0	8.2	11.2
Balance Sheet Impact:			
(Component of) reduction in capital expenditures	1.2	(0.3)	3.1
Component of (reduction in) amount due to Summer Station co-owner	0.4	(0.1)	0.7
Total Pension Income	$16.8	$ 6.8	$25.5

For the last several years, the market value of SCE&G's retirement plan (pension) assets has exceeded the total actuarial present value of accumulated plan benefits. Pension income's sharp decline in 2003 and its increase in 2004 are consistent with overall investment market results. See also the discussion of pension accounting in Critical Accounting Estimates.

Allowance for Funds Used During Construction (AFC)

AFC is a utility accounting practice whereby a portion of the cost of both equity and borrowed funds used to finance construction (which is shown on the balance sheet as construction work in progress) is capitalized. The Company includes an equity portion of AFC in nonoperating income and a debt portion of AFC in interest charges (credits) as noncash items, both of which have the effect of increasing reported net income. AFC represented approximately 6.7% of income before income taxes in 2004, 8.6% in 2003 and 9.2% in 2002.

The decrease in AFC for 2004 vs 2003 is primarily due to completion of the Jasper County Electric Generating Station in May 2004. The decrease in AFC for 2003 vs 2002 is primarily the result of the completion of the Urquhart Station repowering project in June 2002. In addition, in January 2003 the SCPSC issued an order allowing SCE&G to include all Jasper County generating project expenditures as of December 31, 2002 and other construction work in progress expenditures as of June 30, 2002 in its electric rate base. At the time the expenditures were included in the rate base, AFC was no longer calculated on those amounts. These decreases were partially offset by increased AFC from subsequent construction expenditures related to the Jasper County generating and Lake Murray Dam projects (see discussion at CAPITAL PROJECTS).

Dividends Declared

SCE&G's Board of Directors has declared the following dividends on common stock held by SCANA during 2004:

Declaration Date	Dividend Amount	Quarter Ended	Payment Date
February 19, 2004	$36.0 million	March 31, 2004	April 1, 2004
April 29, 2004	$37.0 million	June 30, 2004	July 1, 2004
July 29, 2004	$36.0 million	September 30, 2004	October 1, 2004
October 29, 2004	$36.5 million	December 31, 2004	January 1, 2005

Electric Operations

Electric Operations is comprised of the electric operations of SCE&G, GENCO and Fuel Company. Electric operations sales margins for 2004, 2003 and 2002 were as follows:

	2004	% Change	2003	% Change	2002
			Millions of dollars		
Operating revenues	$1,692.0	15.0%	$1,471.7	6.3%	$1,384.8
Less: Fuel used in generation	466.9	39.8%	334.1	1.4%	329.6
Purchased power	50.7	(20.8)%	64.0	52.0%	42.1
Margin	$1,174.4	9.4%	$1,073.6	6.0%	$1,013.1

- 2004 vs 2003 Margin increased primarily due to increased off-system sales of $47.2 million, increased customer growth and consumption of $22.9 million, $22.3 million due to favorable weather and $7.1 million due to the increase in retail electric base rates effective February 2003. Fuel used in generation increased approximately $103.0 million due to increased availability of generation facilities and approximately $30.0 million due to increased cost of coal. Purchased power decreased due to greater availability of generation facilities.
- 2003 vs 2002 Margin increased primarily due to the increase in retail electric base rates effective February 2003 totaling $63.6 million and customer growth and increased consumption of $24.3 million, partially offset by $27.3 million due to less favorable weather. Fuel used in generation increased by $9.3 million due to the increased cost of natural gas and fuel oil for the Urquhart combined cycle gas turbines and by $1.1 million due to the increased cost of nuclear fuel, partially offset by $5.5 million due to planned plant outages throughout the year. Purchased power increased due to planned plant outages throughout the year.

MWh sales volumes by classes, related to the electric margin above, were as follows:

Classification (in thousands)	2004	% Change	2003	% Change	2002
Residential	7,460	6.6%	6,998	(3.2)%	7,230
Commercial	6,919	4.5%	6,622	(0.5)%	6,658
Industrial	6,775	3.5%	6,548	0.7%	6,505
Sales for resale (excluding interchange)	2,472	71.9%	1,438	(0.7)%	1,448
Other	526	5.2%	500	(6.5)%	535
Total territorial	24,152	9.3%	22,106	(1.2)%	22,376
NMST	898	*	425	(40.0)%	709
Total	25,050	11.2%	22,531	(2.4)%	23,085

* Greater than 100%

- 2004 vs 2003 Territorial sales volumes increased primarily due to more favorable weather, customer growth and consumption and increased off-system sales. NMST volumes increased primarily due to increased availability of generating plants that increased volumes available for resale.
- 2003 vs 2002 Territorial sales volume decreased primarily due to less favorable weather. NMST volumes decreased primarily due to planned outages at generation plants that reduced volumes available for resale.

Gas Distribution

Gas Distribution is comprised of the local distribution operations of SCE&G. Gas distribution sales margins (including transactions with affiliates) for 2004, 2003 and 2002 were as follows:

	2004	% Change	2003	% Change	2002
	Millions of dollars				
Operating revenues	$397.4	10.4%	$360.1	20.8%	$298.2
Less: Gas purchased for resale	313.6	16.7%	268.8	27.3%	211.1
Margin	$ 83.8	(8.2)%	$ 91.3	4.8%	$ 87.1

- 2004 vs 2003 — Margin decreased primarily due to a decreased billing surcharge for the recovery of environmental remediation expenses of $5.0 million and lower residential and commercial sales volumes of $2.5 million.
- 2003 vs 2002 — Margin increased primarily due to customer growth and increased consumption totaling $7.2 million, partially offset by a decrease in industrial usage of $3.0 million primarily due to an unfavorable competitive position of natural gas relative to alternate fuels.

DT sales volumes by classes, including transportation gas were as follows:

Classification (in thousands)	2004	% Change	2003	% Change	2002
Residential	12,916	(2.5)%	13,243	8.2%	12,242
Commercial	12,155	(1.4)%	12,322	5.2%	11,718
Industrial	15,087	3.9%	14,524	(11.5)%	16,419
Transportation gas	2,272	6.1%	2,141	(9.8)%	2,373
Total	42,430	0.5%	42,230	(1.2)%	42,752

- 2004 vs 2003 — Residential and commercial sales volumes decreased primarily due to unfavorable consumption patterns. Industrial and transportation volumes increased in 2004 primarily as a result of interruptible customers using gas instead of alternative fuels.
- 2003 vs 2002 — Residential and commercial sales volumes increased primarily due to more favorable weather. Industrial and transportation volumes decreased in 2003 primarily as a result of interruptible customers using their alternate fuel sources during the year.

Other Operating Expenses

Other operating expenses were as follows:

	2004	% Change	2003	% Change	2002
	Millions of dollars				
Other operation and maintenance	$431.0	6.9%	$403.0	7.1%	$376.2
Depreciation and amortization	220.9	12.6%	196.2	10.0%	178.4
Other taxes	131.4	4.3%	126.0	10.1%	114.4
Total	$783.3	8.0%	$725.2	8.4%	$669.0

- 2004 vs 2003 Other operation and maintenance expenses increased primarily due to increased labor and benefit expense of $19.5 million, $11.0 million of increased operating expenses at the electric generation plants and $2.5 million of expenses associated with winter storm restoration, partially offset by increased pension income of $5.2 million. Depreciation and amortization increased by $13.4 million due to completion of the Jasper County Electric Generating Station and $11.1 million attributed to normal additions. Other taxes increased primarily due to property taxes.
- 2003 vs 2002 Other operation and maintenance expenses increased primarily due to lower pension income of $11.5 million, increased labor and benefit costs of $9.8 million, and increased nuclear operating expenses of $4.5 million. Depreciation and amortization increased by $10.7 million due to normal net property increases, by $4.2 million due to the completion of the Urquhart Station repowering project in June 2002 and by $2.7 million due to amortization of franchise fees. Other taxes increased primarily due to increased property taxes.

Interest Expense

Components of interest expense, excluding the debt component of AFC, were as follows:

	2004	% Change	2003	% Change	2002
			Millions of dollars		
Interest on long-term debt, net	$144.8	3.7%	$139.7	9.5%	$127.6
Other interest expense	3.5	(52.1)%	7.3	—	7.3
Total	$148.3	0.9%	$147.0	9.0%	$134.9

- 2004 vs 2003 Interest on long-term debt increased $5.1 million, primarily due to slightly higher levels of borrowing outstanding during 2004 until the payment of maturing debt late in the year.
- 2003 vs 2002 Interest expense increased by $10.9 million, primarily due to a $22.0 million increase from additional borrowings, which was partially offset by $10.2 million as a result of lower interest rates.

Income Taxes

Income taxes increased approximately $10.1 million for the year 2004 compared to 2003 and decreased approximately $5.2 million for the year 2003 compared to 2002. The Company's effective tax rate for 2004, 2003 and 2002 was approximately 34.0%, 33.1% and 34.3%, respectively. Changes in income taxes are primarily due to changes in operating income. SCE&G's effective tax rate has also been favorably impacted in recent years by the flow-through of state investment tax credits and the recovery of the equity portion of AFC.

LIQUIDITY AND CAPITAL RESOURCES

The Company's cash requirements arise primarily from its operational needs, funding its construction program and payment of dividends to SCANA. The ability of the Company to replace existing plant investment, as well as to expand to meet future demand for electricity and gas, will depend upon its ability to attract the necessary financial capital on reasonable terms. SCE&G recovers the costs of providing services through rates charged to customers. Rates for regulated services are generally based on historical costs. As customer growth and inflation occur and SCE&G continues its ongoing construction program, SCE&G expects to seek increases in rates. The Company's future financial position and results of operations will be affected by SCE&G's ability to obtain adequate and timely rate and other regulatory relief, if requested.

In a January 2005 order the SCPSC granted SCE&G a composite increase in retail electric rates of approximately 2.89%, designed to produce additional annual revenues of approximately $41.4 million based on a test year calculation. The SCPSC lowered SCE&G's return on common equity from 12.45% to a range of between 10.4% and 11.4%, with rates to be set at 10.7%. The new rates became effective in January 2005. As part of its order, the SCPSC approved SCE&G's recovery of construction and operating costs for SCE&G's new Jasper County Electric Generating Station, recovery of costs of mandatory environmental upgrades primarily related to Federal Clean Air Act regulations and the application of current and anticipated net synthetic fuel tax credits to offset the cost of constructing the back-up dam at Lake Murray. The SCPSC also approved recovery of SCE&G's approximately $14 million of costs incurred in the formation of the GridSouth Regional Transmission Organization over a five-year period, and recovery through base rates over three years of approximately $25.6 million of purchased power costs that were previously deferred. As a part of its order, the SCPSC extended through 2010 its approval of the accelerated capital recovery plan for SCE&G's Cope Generating Station. Under the plan, based on the level of revenues and operating expenses, SCE&G may increase depreciation of its Cope Generating Station in excess of amounts that would be recorded based upon currently approved depreciation rates, not to exceed $36 million annually, without additional approval of the SCPSC. Any unused portion of the $36 million in any given year may be carried forward for possible use in the following year.

The Company's current estimates of its cash requirements for construction and nuclear fuel expenditures for 2005-2007, which are subject to continuing review and adjustment, are as follows:

Estimated Cash Requirements

	2005	2006	2007
	Millions of dollars		
SCE&G:			
Electric Plant:			
Generation (including GENCO)	$ 86	$145	$101
Transmission	44	51	27
Distribution	115	110	107
Other	15	16	17
Nuclear Fuel	23	26	25
Gas	30	30	28
Common	31	13	12
Other	4	1	—
Total SCE&G	$348	$392	$317

The Company's contractual cash obligations as of December 31, 2004 are summarized as follows:

Contractual Cash Obligations

December 31, 2004 (Millions of dollars)	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
Long-term and short-term debt (including interest and preferred stock)	$4,501	$448	$ 527	$329	$3,197
Capital leases	1	1	—	—	—
Operating leases	48	12	29	7	—
Purchase obligations	91	61	28	—	2
Other commercial commitments	765	311	443	1	10
Total	$5,406	$833	$1,027	$337	$3,209

Included in other commercial commitments are estimated obligations for coal and nuclear fuel purchases and certain obligations related to the Lake Murray Dam reinforcement project. See Note 10 to the consolidated financial statements.

Included in purchase obligations are customary purchase orders under which SCE&G has the option to utilize certain vendors without the obligation to do so. SCE&G may terminate such obligations without penalty.

The Company also has a legal obligation associated with the decommissioning and dismantling of Summer Station that is not listed in the contractual cash obligations above. See Note 1 to the consolidated financial statements.

The Company anticipates that its contractual cash obligations will be met through internally generated funds and the incurrence of additional short-term and long-term indebtedness. The Company expects that it has or can obtain adequate sources of financing to meet its projected cash requirements for the foreseeable future.

Cash outlays for 2005 (estimated) and 2004 (actual) for certain expenditures are as follows:

	2005	2004
	Millions of dollars	
Property additions and construction expenditures, net of AFC	$325	$422
Nuclear fuel expenditures	23	22
Investments	18	19
Total	$366	$463

Included in cash outlays are the following specific projects:

- FERC mandated that SCE&G's Lake Murray Dam be reinforced to comply with new federal safety standards. Construction for the project and related activities is expected to be complete in 2005 at a cost of approximately $275 million (excluding AFC), of which approximately $240 million had been incurred through December 31, 2004.
- SCE&G completed construction on its 880 MW generation plant in Jasper County, South Carolina in May 2004. The plant includes three natural gas combustion-turbine generators and one steam-turbine generator. The total cost of the project was approximately $506 million, which includes the original construction costs for the plant itself, as well as AFC and other project-related costs. All such costs have been approved for recovery in rate base.

Financing Limits and Related Matters

The Company's issuance of various securities, including long-term and short-term debt, is subject to customary approval or authorization by state and federal regulatory bodies including the SCPSC and the SEC. The following describes the financing programs currently utilized by the Company.

At December 31, 2004 SCE&G and Fuel Company had available the following lines of credit and short-term borrowings outstanding:

	Millions of dollars
Lines of credit (total and unused):	
SCE&G and Fuel Company	
Committed (expires June 2009)	$ 525
Uncommitted	113[(1)]
Short-term borrowings outstanding:	
Commercial paper (270 or fewer days)	$152.9
Weighted average interest rate	2.40%

(1) Lines of credit that either the Company or SCANA may use.

SCE&G's First and Refunding Mortgage Bond Indenture, dated January 1, 1945 (Old Mortgage) and covering substantially all of its properties, prohibits the issuance of additional bonds (Class A Bonds) unless net earnings (as therein defined) for 12 consecutive months out of the 18 months prior to the month of issuance are at least twice the annual interest requirements on all Class A Bonds to be outstanding (Bond Ratio). For the year ended December 31, 2004 the Bond Ratio was 5.72. The Old Mortgage allows the issuance of Class A Bonds up to an additional principal amount equal to (i) 70% of unfunded net property additions (which unfunded net property additions totaled approximately $1,401.2 million at December 31, 2004), (ii) retirements of Class A Bonds (which retirement credits totaled $121.4 million at December 31, 2004), and (iii) cash on deposit with the Trustee.

SCE&G is also subject to a bond indenture dated April 1, 1993 (New Mortgage) covering substantially all of its electric properties under which its future mortgage-backed debt (New Bonds) will be issued. New Bonds are issued under the New Mortgage on the basis of a like principal amount of Class A Bonds issued under the Old Mortgage which have been deposited with the Trustee of the New Mortgage. At December 31, 2004 approximately $1.0 billion Class A Bonds were on deposit with the Trustee of the New Mortgage and are available to support the issuance of additional New Bonds. New Bonds will be issuable under the New Mortgage only if adjusted net earnings (as therein defined) for 12 consecutive months out of the 18 months immediately preceding the month of issuance are at least twice the annual interest requirements on all outstanding bonds (including Class A Bonds) and New Bonds to be outstanding (New Bond Ratio). For the year ended December 31, 2004 the New Bond Ratio was 5.57.

SCE&G's Restated Articles of Incorporation (the Articles) prohibit issuance of additional shares of preferred stock without the consent of the preferred shareholders unless net earnings (as defined therein) for the 12 consecutive months immediately preceding the month of issuance are at least one and one-half times the aggregate of all interest charges and preferred stock dividend requirements on all shares of preferred stock outstanding immediately after the proposed issue (Preferred Stock Ratio). For the year ended December 31, 2004 the Preferred Stock Ratio was 1.71.

The Articles also require the consent of a majority of the total voting power of SCE&G's preferred stock before SCE&G may issue or assume any unsecured indebtedness if, after such issue or assumption, the total principal amount of all such unsecured indebtedness would exceed ten percent of the aggregate principal amount of all of SCE&G's secured indebtedness and capital and surplus (the ten percent test). No such consent is required to enter into agreements for payment of principal, interest and premium for securities issued for pollution control purposes. At December 31, 2004 the ten percent test would have limited issuances of unsecured indebtedness to approximately $415.3 million. Unsecured indebtedness at December 31, 2004 totaled approximately $154.1 million, and was comprised of short-term borrowings and the interest-free borrowing discussed below.

In 2004 SCE&G borrowed $35.4 million under an agreement with the South Carolina Transportation Infrastructure Bank (the Bank) and the South Carolina Department of Transportation (SCDOT) that allows SCE&G to borrow funds from the Bank to construct a roadbed for SCDOT in connection with the Lake Murray Dam remediation project. The loan agreement provides for interest-free borrowings of up to $59 million with such borrowings being repaid over ten years from the initial borrowing. At December 31, 2004 SCE&G had $32.5 million outstanding under the agreement.

Financing Cash Flows

During 2004 the Company experienced net cash outflows related to financing activities of approximately $110 million primarily due to the payment of dividends.

In anticipation of the issuance of debt, the Company may use interest rate lock or similar agreements to manage interest rate risk. Payments received or made upon termination of such agreements are recorded within other deferred debits or credits on the balance sheet and are amortized to interest expense over the term of the underlying debt.

For additional information on significant financing transactions, see Note 4 to the Company's consolidated financial statements.

ENVIRONMENTAL MATTERS

Capital Expenditures

In the years 2002 through 2004, the Company's capital expenditures for environmental control totaled approximately $269.3 million. These expenditures were in addition to expenditures included in "Other operation and maintenance" expenses, which were approximately $21.3 million, $29.0 million, and $29.7 million during 2004, 2003 and 2002, respectively. It is not possible to estimate all future costs related to environmental matters, but forecasts for capitalized environmental expenditures for the Company are $31.6 million for 2005 and $360.1 million for the four-year period 2006 through 2009. These expenditures are included in the Company's construction program discussed in Liquidity and Capital Resources, and include the matters discussed below.

Electric Operations

The CAA required electric utilities to substantially reduce emissions of sulfur dioxide and NOx by the year 2000. The Company remains in compliance with these requirements. In 1998 the EPA required the State of South Carolina, among other states, to modify its state implementation plan (SIP) to address the issue of NOx pollution. South Carolina's SIP requires additional emissions reductions in 2004 and beyond. Further, the EPA had indicated that it would finalize regulations by March 2005 for stricter limits on mercury generated by coal-fired plants. Further reductions in sulfur dioxide and NOx are expected to be proposed in 2005. New legislation may also impose stringent requirements on power plants to reduce emissions of sulfur dioxide, NOx and mercury. It is also possible that new initiatives will be introduced to reduce carbon dioxide emissions. The Company cannot predict whether such legislation will be enacted, and if it is, the conditions the legislation would impose on utilities.

The EPA has undertaken an aggressive enforcement initiative against the utilities industry, and the DOJ has brought suit against a number of utilities in federal court alleging violations of the CAA. At least two of these suits have either been tried or have had substantive motions decided—one favorable to the industry and one not. Neither is binding as precedent on the Company. Prior to the suits, those utilities had received requests for information under Section 114 of the CAA and were issued Notices of Violation. The basis for these suits is the assertion by the EPA, under a stringent rule known as New Source Review (NSR), that maintenance activities undertaken by the utilities over the past 20 or more years constitute "major modifications" which would have required the installation of costly Best Available Control Technology (BACT). SCE&G and GENCO have received and responded to Section 114 requests for information related to Canadys, Wateree and Williams Stations. The regulations under the CAA provide certain exemptions to the definition of "major modifications," including an exemption for routine repair, replacement or maintenance. On October 27, 2003 EPA published a final revised NSR rule in the Federal Register with an effective date of December 26, 2003. The new rule represents an industry-favorable departure from certain positions advanced by the federal government in the NSR enforcement initiative. However, on motion of several Northeastern states, the United States Circuit Court of Appeals for the District of Columbia stayed the effect of the final rule. The ultimate application of the final rule to the Company is uncertain. The Company has analyzed each of the activities covered by the EPA's requests and believes each of these activities is covered by the exemption for routine repair, replacement and maintenance under what it believes is a fair reading of both the prior regulation and the contested revised regulation. The regulations also provide an exemption for an increase in emissions resulting from increased hours of operation or production rate and from demand growth. The current state of continued DOJ enforcement actions is the subject of industry-wide speculation, but it is possible that the EPA will commence enforcement actions against SCE&G and GENCO, and the EPA has the authority to seek penalties at the rate of up to $27,500 per day for each violation. The EPA also could seek installation of BACT (or equivalent) at the three plants. The Company believes that any enforcement actions relative to the Company's compliance with the CAA would be without merit. However, if successful, such actions could have a material adverse effect on the Company's financial condition, cash flows and results of operations. To comply with current and anticipated state and federal regulations, SCE&G and GENCO expect to incur capital expenditures totaling approximately $193.3 million over the 2005-2008 period to retrofit existing facilities, with increased operation and maintenance costs of approximately $2.4 million per year. SCE&G and GENCO expect to have increased operation and maintenance costs of approximately $9.6 million in 2009. To meet compliance requirements for the years 2010 through 2014, the Company anticipates additional capital expenditures totaling approximately $160.1 million.

The Clean Water Act, as amended, provides for the imposition of effluent limitations that require treatment for wastewater discharges. Under this Act, compliance with applicable limitations is achieved under a national permit program. Discharge permits have been issued for all, and renewed for nearly all, of SCE&G's and GENCO's generating units. Concurrent with renewal of these permits, the permitting agency has implemented a more rigorous program of monitoring and controlling thermal discharges, has modified the requirements for cooling water intake structures, and has required strategies for toxicity reduction in wastewater streams. The Company is developing compliance plans for these initiatives. Congress is expected to consider further amendments to the Clean Water Act. Such legislation may include limitations to mixing zones and toxicity-based standards. These provisions, if passed, could have a material impact on the financial condition and results of operations and cash flows of the Company.

Nuclear Fuel Disposal

The Nuclear Waste Policy Act of 1982 required that the United States government, by January 31, 1998, accept and permantly dispose of high-level radioactive waste and spent nuclear fuel and imposes a fee of 1.0 mil per KWh of net nuclear generation after April 7, 1983. The Act also imposes on utilities the primary responsibility for storage of their spent nuclear fuel until the repository is available. SCE&G entered into a Standard Contract for Disposal of Spent Nuclear Fuel and/or High-Level Radioactive Waste (Standard Contract) with the DOE in 1983 providing for permanent disposal of its spent nuclear fuel in exchange for agreed payments at particular amounts. On January 28, 2004 SCE&G and Santee Cooper (one-third owner of Summer Station) filed suit in the Court of Federal Claims against the DOE for breach of the Standard Contract, because as of the date of filing, the federal government has accepted no spent fuel from Summer Station or any other utility for transport and disposal, and has indicated that it does not anticipate doing so until 2010, at the earliest. As a consequence of the federal government's breach of contract, the plaintiffs have incurred and will continue to incur substantial costs. There are two additional causes of action alleged as well—damages for breach of the implied covenant of good faith and fair dealing and a takings claim demanding just compensation for the taking of the plaintiffs' real property through the cost of storage. SCE&G has on-site spent nuclear fuel storage capability until at least 2018 and expects to be able to expand its storage capacity to accommodate the spent nuclear fuel output for the life of the plant through dry cask storage or other technology as it becomes available.

Gas Distribution

The Company maintains an environmental assessment program to identify and evaluate current and former operations sites that could require environmental cleanup. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and clean up each site. These estimates are refined as additional information becomes available; therefore, actual expenditures may differ significantly from the original estimates. Amounts estimated and accrued to date for site assessments and cleanup relate solely to regulated operations and are recorded in deferred debits and amortized with recovery provided through rates. Deferred amounts, net of amounts previously recovered through rates and insurance settlements, totaled $10.5 million and $10.9 million at December 31, 2004 and 2003, respectively. The deferral includes the estimated costs associated with the following matters:

- SCE&G owns a decommissioned MGP site in the Calhoun Park area of Charleston, South Carolina. The site is currently being remediated for contamination. SCE&G anticipates that the remaining remediation activities will be completed by the end of 2005, with certain monitoring and other activities continuing until 2010. As of December 31, 2004, SCE&G has spent approximately $20.5 million to remediate the Calhoun Park site, and expects to spend an additional $1.3 million. In addition, SCE&G is party to certain claims for costs and damages from this site, for which claims the National Park Service of the Department of the Interior made an initial demand for payment of approximately $9 million. Any costs arising from these matters are expected to be recoverable through rates under South Carolina regulatory processes.
- SCE&G owns three other decommissioned MGP sites in South Carolina which contain residues of by-product chemicals. One of the sites has been remediated and will undergo routine monitoring until released by DHEC. The other two sites are currently being investigated under work plans approved by DHEC. SCE&G anticipates that major remediation activities for the three sites will be completed in 2010. As of December 31, 2004, SCE&G has spent approximately $4 million related to these three sites, and expects to spend an additional $4 million.

REGULATORY MATTERS

The Company is subject to the jurisdiction of the SCPSC as to retail electric and gas rates, service, accounting, issuance of securities (other than short-term borrowings) and other matters. Material retail rate proceedings are described in more detail in Note 2 to the consolidated financial statements.

In a January 2005 order the SCPSC granted SCE&G a composite increase in retail electric rates of approximately 2.89%, designed to produce additional annual revenues of approximately $41.4 million based on a test year calculation. The SCPSC lowered SCE&G's return on common equity from 12.45%

to a range of between 10.4% and 11.4%, with rates to be set at 10.7%. The new rates became effective in January 2005. As part of its order, the SCPSC approved the Company's recovery of construction and operating costs for the Company's new Jasper County Electric Generating Station, recovery of costs of mandatory environmental upgrades primarily related to Federal Clean Air Act regulations and the application of current and anticipated net synthetic fuel tax credits to offset the cost of constructing the back-up dam at Lake Murray. The SCPSC also approved recovery over a five-year period of the Company's approximately $14 million of costs incurred in the formation of the GridSouth Regional Transmission Organization and recovery through base rates over three years of approximately $25.6 million of purchased power costs that were previously deferred. As a part of its order, the SCPSC extended through 2010 its approval of the accelerated capital recovery plan for SCE&G's Cope Generating Station. Under the plan, based on the level of revenues and operating expenses, SCE&G may increase depreciation of its Cope Generating Station in excess of amounts that would be recorded based upon currently approved depreciation rates, not to exceed $36 million annually, without additional approval of the SCPSC. Any unused portion of the $36 million in any given year may be carried forward for possible use in the following year.

Synthetic Fuel Investments

SCE&G holds two equity-method investments in partnerships involved in converting coal to non-conventional fuel, the use of which fuel qualifies for federal income tax credits. The aggregate investment in these partnerships as of December 31, 2004 is approximately $3.4 million, and through December 31, 2004, they have generated and passed through to SCE&G approximately $140.5 million in such tax credits. At December 31, 2004 SCE&G has recorded on its balance sheet $96.7 million net deferred fuel tax benefits, which includes the effects of partnership losses.

Under a plan approved by the SCPSC, any tax credits generated by the partnerships and ultimately passed through to SCE&G from synfuel produced for and consumed by SCE&G, net of partnership losses and other expenses, have been and will be deferred and will be applied to offset the capital costs of constructing the back-up dam at Lake Murray. See Note 2 to the consolidated financial statements.

In March 2004, one of the partnerships, S.C. Coaltech No. 1 L.P., received a "No Change" letter from the Internal Revenue Service (IRS) related to its synthetic fuel operations for the tax year 2000. After review of testing procedures and supporting documentation and conducting an independent investigation, the IRS found that the partnership produces a qualifying fuel under section 29 of the Internal Revenue Code (IRC) and found no reason to challenge the first placed-in-service status of the facility. This letter supports the Company's position that the synthetic fuel tax credits have been properly claimed.

In order to earn these tax credits SCANA must be subject to a regular federal income tax liability in an amount at least equal to the credits generated in any taxable year. This tax liability could be insufficient if SCANA's consolidated taxable income were to be significantly reduced as the result of realizing lower income or large deductions in any taxable year.

Section 29 of the IRC provides for the reduction of synthetic fuel tax credits for any calendar year in which the average annual wellhead price of oil exceeds an inflation-adjusted base price per barrel (as defined in the IRC, and currently estimated to be approximately $52), up to a maximum price spread (as defined in the IRC, and currently estimated to be in the range of $12-$13), at which point the credits would be completely phased-out. The Company cannot predict what impact, if any, the price of oil may have on the Company's ability to earn synthetic fuel tax credits in the future.

The availability of these synthetic fuel tax credits is also subject to coal availability and other operational risks related to the generating plants, including those described in the Risk Factors section within Item 1, Business.

Nuclear License Extension

In April 2004 the NRC approved SCE&G's application with the NRC for a 20-year license extension for its Summer Station. The extension allows the plant to operate through August 6, 2042.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Following are descriptions of the Company's accounting policies which are new or most critical in terms of reporting financial condition or results of operations.

Utility Regulation

The Company is subject to the provisions of SFAS 71, *"Accounting for the Effects of Certain Types of Regulation,"* which requires it to record certain assets and liabilities that defer the recognition of expenses and revenues to future periods as a result of being rate-regulated. In the future, as a result of deregulation or other changes in the regulatory environment, the Company may no longer meet the criteria for continued application of SFAS 71 and could be required to write off its regulatory assets and liabilities. Such an event could have a material adverse effect on the results of operations of the Company's Electric Distribution and Gas Distribution segments in the period the write-off would be recorded. It is not expected that cash flows or financial position would be materially affected. See Note 1 to the consolidated financial statements for a description of the Company's regulatory assets and liabilities, including those associated with the Company's environmental assessment program.

The Company's generation assets would be exposed to considerable financial risks in a deregulated electric market. If market prices for electric generation do not produce adequate revenue streams and the enabling legislation or regulatory actions do not provide for recovery of the resulting stranded costs, the Company could be required to write down its investment in those assets. The Company cannot predict whether any write-downs will be necessary and, if they are, the extent to which they would adversely affect the Company's results of operations in the period in which they would be recorded. As of December 31, 2004 the Company's net investments in fossil/hydro and nuclear generation assets were approximately $2.5 billion and $556 million, respectively.

Revenue Recognition and Unbilled Revenues

Revenues related to the sale of energy are recorded when service is rendered or when energy is delivered to customers. Because customers are billed on cycles which vary based on the timing of the actual reading of their electric and gas meters, the Company records estimates for unbilled revenues at the end of each reporting period. Such unbilled revenue amounts reflect estimates of the amount of energy delivered to each customer since the date of the last reading of their respective meters. Such unbilled revenues reflect consideration of estimated usage by customer class, the effects of different rate schedules, changes in weather and, where applicable, the impact of weather normalization provisions of rate structures. The accrual of unbilled revenues in this manner properly matches revenues and related costs. As of December 31, 2004 and 2003, accounts receivable included unbilled revenues of $48.1 million and $50.0 million, respectively, compared to total revenues for 2004 and 2003 of $2.1 billion and $1.8 billion, respectively.

Nuclear Decommissioning

Accounting for decommissioning costs for nuclear power plants involves significant estimates related to costs to be incurred many years in the future. Among the factors that could change the Company's accounting estimates related to decommissioning costs are changes in technology, changes in regulatory and environmental remediation requirements, as well as changes in financial assumptions such as discount rates and timing of cash flows. Changes in any of these estimates could significantly impact the Company's financial position and cash flows (although changes in such estimates should be earnings-neutral, because these costs are expected to be collected from ratepayers).

The Company's share of estimated site-specific nuclear decommissioning costs for Summer Station, including the cost of decommissioning plant components not subject to radioactive contamination, totals approximately $357 million, stated in 1999 dollars. This estimate is based on a decommissioning study completed in 2000 and has not been updated to incorporate the 20-year license extension for Summer Station received in 2004. Santee Cooper is responsible for decommissioning costs related to its one-third ownership interest in the station. The cost estimate is based on a decommissioning methodology acceptable to the NRC under which the site would be maintained over a period of approximately 60 years in such a manner as to allow for subsequent decontamination that permits release for unrestricted use.

Under the Company's method of funding decommissioning costs, funds collected through rates are invested in insurance policies on the lives of certain Company and affiliate personnel. SCE&G is the beneficiary of these policies. Through these insurance contracts, SCE&G is able to take advantage of income tax benefits and accrue earnings on the fund on a tax-deferred basis. Amounts for decommissioning collected through electric rates, insurance proceeds, and interest on proceeds, less expenses, are transferred by SCE&G to an external trust fund. Management intends for the fund, including earnings thereon, to provide for all eventual decommissioning expenditures on an after-tax basis.

Accounting for Pensions and Other Postretirement Benefits

The Company follows SFAS 87, "Employers' Accounting for Pensions," in accounting for its defined benefit pension plan. The Company's plan is fully funded and as such, net pension income is reflected in the financial statements (see Results of Operations). SFAS 87 requires the use of several assumptions, the selection of which may have a large impact on the resulting benefit recorded. Among the more sensitive assumptions are those surrounding discount rates and returns on assets. Net pension income of $16.8 million recorded in 2004 reflects the use of a 6.0% discount rate and an assumed 9.25% long-term rate of return on plan assets. The Company believes that these assumptions were, and that the resulting pension income amount was, reasonable. For purposes of comparison, using a discount rate of 5.75% in 2004 would have increased the Company's pension income approximately $0.3 million. Had the assumed long-term rate of return on assets been reduced to 9.0% in 2004, the Company's pension income would have been reduced by approximately $1.8 million.

In determining the appropriate discount rate, the Company considers the market indices of high-quality long-term fixed income securities. As such, the Company selected the beginning of year discount rate of 6.0% as being within a reasonable range of interest rates for obligations rated Aa by Moody's as of January 1, 2004. This same discount rate was also selected for determination of other postemployment benefits costs discussed below.

The following information with respect to pension assets (and returns thereon) should also be noted:

The Company determines the fair value of substantially all of its pension assets utilizing market quotes rather than utilizing any calculated values, "market related" values or other modeling techniques. In developing the expected long-term rate of return assumptions, the Company evaluated input from actuaries and from pension fund investment advisors, including such advisors' review of the plan's historical 10, 15, 20 and 25 year cumulative actual returns of 12.1%, 11.3%, 12.5% and 12.7%, respectively, all of which have been in excess of related broad indices. The Company anticipates that the investment managers will continue to generate long-term returns of at least 9.25%.

The expected long-term rate of return of 9.25% is based on a target asset allocation of 70% with equity managers and 30% with fixed income managers. Management regularly reviews such allocations and periodically rebalances the portfolio to the targeted allocation when considered appropriate.

While investment performance in 2000-2002 and lower discount rates have significantly reduced pension income from previous or historical levels, the pension trust has been and remains adequately funded, and no contributions have been required since 1997. As such, these occurrences have had no impact on the Company's cash flows. Based on stress testing performed by the Company's actuaries, management does not anticipate the need to make pension contributions until after 2009.

Similar to its pension accounting, the Company follows SFAS 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions," in accounting for its postretirement medical and life insurance benefits. This plan is unfunded, so no assumptions related to rate of return on assets impact the net expense recorded; however, the selection of discount rates can significantly impact the actuarial determination of net expense. The Company used a discount rate of 6.0% and recorded a net SFAS 106 cost of $13.4 million for 2004. Had the selected discount rate been 5.75%, the expense for 2004 would have been approximately $0.1 million higher.

Asset Retirement Obligations

SFAS 143 provides guidance for recording and disclosing liabilities related to future legally enforceable obligations to retire assets (ARO). SFAS 143 applies to the legal obligation associated with the retirement of long-lived tangible assets that result from their acquisition, construction, development and normal operation. Because such obligation relates solely to the Company's regulated electric operations, adoption of SFAS 143 had no impact on results of operations. As of January 1, 2003, the Company had recorded an ARO of approximately $111 million, which exceeded the previously recorded reserve for nuclear plant decommissioning of approximately $87 million. At December 31, 2004 such ARO totaled approximately $124 million.

The Company believes that there is legal uncertainty as to the existence of environmental obligations associated with certain of its electric transmission and distribution properties. The Company believes that any ARO related to this type of property would be insignificant and, due to the indeterminate life of the related assets, an ARO could not be reasonably estimated.

OTHER MATTERS

Claims and Litigation

For a description of claims and litigation see Item 3. LEGAL PROCEEDINGS and Note 10 to the consolidated financial statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

All financial instruments held by SCE&G described below are held for purposes other than trading.

Interest rate risk—The tables below provide information about long-term debt issued by SCE&G which is sensitive to changes in interest rates. For debt obligations the tables present principal cash flows and related weighted average interest rates by expected maturity dates. Fair values for debt represent quoted market prices.

December 31, 2004 Millions of dollars	Expected Maturity Date							
	2005	2006	2007	2008	2009	Thereafter	Total	Fair Value
Liabilities								
Long-Term Debt:								
Fixed Rate ($)	189.2	169.9	39.2	39.2	139.2	1,718.2	2,294.9	2,285.7
Average Interest Rate (%)	7.37	8.51	6.86	6.86	6.33	6.02	6.36	N/A

December 31, 2003 Millions of dollars	Expected Maturity Date							
	2004	2005	2006	2007	2008	Thereafter	Total	Fair Value
Liabilities								
Long-Term Debt:								
Fixed Rate ($)	139.2	189.2	169.9	39.2	39.2	1,721.9	2,298.6	2,239.8
Average Interest Rate (%)	7.46	7.37	8.51	6.86	6.86	6.06	6.46	

While a decrease in interest rates would increase the fair value of debt, it is unlikely that events which would result in a realized loss will occur.

The above table excludes approximately $81 million and $51 million in long-term debt as of December 31, 2004 and 2003, respectively, which amounts do not have a stated interest rate associated with them.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

South Carolina Electric & Gas Company:

We have audited the accompanying Consolidated Balance Sheets of South Carolina Electric & Gas Company (the "Company") as of December 31, 2004 and 2003, and the related Consolidated Statements of Income, Common Equity and of Cash Flows for each of the three years in the period ended December 31, 2004. Our audits also included the financial statement schedule listed in Part IV at Item 15. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of South Carolina Electric & Gas Company at December 31, 2004 and 2003, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/Deloitte & Touche LLP
Columbia, South Carolina
February 28, 2005

SOUTH CAROLINA ELECTRIC & GAS COMPANY
CONSOLIDATED BALANCE SHEETS

December 31, (Millions of dollars)	2004	2003
Assets		
Utility Plant In Service:	$ 7,096	$ 6,207
Accumulated depreciation and amortization	(1,934)	(1,907)
	5,162	4,300
Construction work in progress	417	951
Nuclear fuel, net of accumulated amortization	42	42
Utility Plant, Net	5,621	5,293
Nonutility Property and Investments:		
Nonutility property, net of accumulated depreciation	27	19
Assets held in trust, net—nuclear decommissioning	49	44
Other investments	6	6
Nonutility Property and Investments, Net	82	69
Current Assets:		
Cash and cash equivalents	20	56
Receivables, net of allowance for uncollectible accounts of $1 and $1	267	238
Receivables—affiliated companies	19	61
Inventories (at average cost):		
Fuel	35	35
Materials and supplies	64	54
Emission allowances	9	6
Prepayments	30	20
Total Current Assets	444	470
Deferred Debits:		
Environmental	11	11
Pension asset, net	285	270
Due from affiliates—pension and postretirement benefits	23	20
Other regulatory assets	376	333
Other	138	162
Total Deferred Debits	833	796
Total	$ 6,980	$ 6,628

December 31, (Millions of dollars)	2004	2003
Capitalization and Liabilities		
Shareholders' Investment:		
Common equity	$ 2,164	$ 2,043
Preferred stock (Not subject to purchase or sinking funds)	106	106
Total Shareholders' Investment	2,270	2,149
Preferred Stock, net (Subject to purchase or sinking funds)	9	9
Long-Term Debt, net	1,981	2,010
Total Capitalization	4,260	4,168
Minority Interest	81	100
Current Liabilities:		
Short-term borrowings	153	140
Current portion of long-term debt	198	142
Accounts payable	106	104
Accounts payable—affiliated companies	113	134
Customer deposits	26	25
Taxes accrued	152	118
Interest accrued	35	39
Dividends declared	38	43
Other	50	42
Total Current Liabilities	871	787
Deferred Credits:		
Deferred income taxes, net	744	707
Deferred investment tax credits	119	114
Asset retirement obligation—nuclear plant	124	118
Other asset retirement obligations	363	265
Due to affiliates—pension and postretirement benefits	14	15
Postretirement benefits	142	135
Other regulatory liabilities	188	164
Other	74	55
Total Deferred Credits	$ 1,768	1,573
Commitments and Contingencies (Note 10)	—	—
Total	$ 6,980	$ 6,628

See Notes to Consolidated Financial Statements.

SOUTH CAROLINA ELECTRIC & GAS COMPANY
CONSOLIDATED STATEMENTS OF INCOME

For the Years Ended December 31, (Millions of dollars)	2004	2003	2002
Operating Revenues:			
Electric	$1,692	$1,472	$1,385
Gas	397	360	298
Total Operating Revenues	2,089	1,832	1,683
Operating Expenses:			
Fuel used in electric generation	467	334	330
Purchased power (including affiliated purchases)	51	64	42
Gas purchased for resale	313	269	211
Other operation and maintenance	431	403	376
Depreciation and amortization	221	196	179
Other taxes	131	126	114
Total Operating Expenses	1,614	1,392	1,252
Operating Income	475	440	431
Other Income:			
Other income, including allowance for equity funds used during construction of $14, $18 and $20	25	35	36
Gain on sale of assets	1	1	1
Total Other Income	26	36	37
Income Before Interest Charges, Minority Interest, Income Taxes and Preferred Stock Dividends	501	476	468
Interest Charges, Net of Allowance for Borrowed Funds Used During Construction of $9, $11 and $12	139	136	123
Dividend Requirement of Company—Obligated Mandatorily Redeemable Preferred Securities	—	2	4
Income Before Interest Charges, Minority Interest, Income Taxes and Preferred Stock Dividends	362	338	341
Minority Interest	10	8	5
Income Before Income Taxes and Preferred Stock Dividends	352	330	336
Income Taxes	120	110	117
Net Income	232	220	219
Preferred Stock Cash Dividends (At stated rates)	7	7	7
Earnings Available for Common Shareholder	$ 225	$ 213	$ 212

See Notes to Consolidated Financial Statements.

SOUTH CAROLINA ELECTRIC & GAS COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31, (Millions of dollars)	2004	2003	2002
Cash Flows From Operating Activities:			
Net income	$ 232	$ 220	$ 219
Adjustments to reconcile net income to net cash provided from operating activities:			
Minority interest	10	8	5
Depreciation and amortization	221	196	178
Amortization of nuclear fuel	22	21	20
Gain on sale of assets	(1)	(1)	(1)
Allowance for funds used during construction	(23)	(29)	(32)
Changes in certain assets and liabilities:			
(Increase) decrease in receivables	13	(50)	(33)
(Increase) decrease in inventories	(13)	30	(10)
(Increase) decrease in prepayments	(10)	4	(18)
(Increase) decrease in pension asset	(15)	(5)	(26)
(Increase) decrease in other regulatory assets	(51)	(34)	3
Increase (decrease) in deferred income taxes, net	44	51	7
Increase (decrease) in other regulatory liabilities	44	47	38
Increase (decrease) in postretirement benefits obligations	7	4	9
Increase (decrease) in accounts payable	(19)	70	14
Increase (decrease) in taxes accrued	34	4	12
Increase (decrease) in interest accrued	(4)	8	4
Changes in fuel adjustment clauses	8	11	9
Changes in other assets	2	(30)	(25)
Changes in other liabilities	34	42	35
Net Cash Provided From Operating Activities	535	567	408
Cash Flows From Investing Activities:			
Utility property additions and construction expenditures, net of AFC	(439)	(650)	(607)
Nonutility property additions	(5)	—	(2)
Proceeds from sales of assets	2	2	2
Investments in affiliates	(19)	(16)	(11)
Net Cash Used For Investing Activities	(461)	(664)	(618)
Cash Flows From Financing Activities:			
Proceeds:			
Issuance of First Mortgage Bonds	—	743	295
Issuance of Pollution Control and Industrial Revenue Bonds	—	36	87
Distributions from parent	38	39	157
Issuance of notes and loans	136	—	—
Repayments:			
Mortgage Bonds	(100)	(350)	(103)
Pollution Control Bonds	—	(47)	(62)
Notes and loans	(10)	(19)	(7)
Payments of deferred financing costs	—	(25)	—
Retirement of preferred stock and trust preferred securities	—	(50)	(1)
Dividend payments:			
Common stock	(151)	(152)	(155)
Preferred stock	(7)	(7)	(7)
Distribution to parent	(29)	—	—
Short-term borrowings, net	13	(38)	13
Net Cash Provided From (Used For) Financing Activities	(110)	130	217
Net Increase (Decrease) in Cash and Cash Equivalents	(36)	33	7
Cash and Cash Equivalents, January 1	56	23	16
Cash and Cash Equivalents, December 31	$ 20	$ 56	$ 23
Supplemental Cash Flow Information:			
Cash paid for—Interest (net of capitalized interest of $9, $11 and $12)	$ 144	$ 125	$ 119
—Income taxes	22	41	65
Noncash Investing and Financing Activities:			
Columbia Franchise Agreement	—	—	30

See Notes to Consolidated Financial Statements.

SOUTH CAROLINA ELECTRIC & GAS COMPANY
CONSOLIDATED STATEMENTS OF COMMON EQUITY

	Common Stock(a)		Premium On Common Stock	Other Paid in Capital	Capital Stock Expense	Retained Earnings	Total Common Equity
	Shares	Amount					
			(Millions)				
Balance at December 31, 2001	40	$181	$395	$470	$(5)	$ 709	$1,750
Capital Contributions From Parent				157			157
Earnings Available for Common Shareholder						212	212
Cash Dividends Declared						(153)	(153)
Balance at December 31, 2002	40	181	395	627	(5)	768	1,966
Capital Contributions From Parent				9			9
Earnings Available for Common Shareholder						213	213
Cash Dividends Declared						(145)	(145)
Balance at December 31, 2003	40	181	395	636	(5)	836	2,043
Capital Contributions From Parent				38			38
Earnings Available for Common Shareholder						225	225
Cash Dividends Declared						(142)	(142)
Balance at December 31, 2004	40	$181	$395	$674	$(5)	$ 919	$2,164

(a) $4.50 par value, authorized 50 million shares

See Notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A. Organization and Principles of Consolidation

South Carolina Electric & Gas Company (SCE&G, and together with its consolidated affiliates, the Company), a public utility, is a South Carolina corporation organized in 1924 and a wholly owned subsidiary of SCANA Corporation (SCANA), a South Carolina corporation and a registered public utility holding company within the meaning of the Public Utility Holding Company Act of 1935, as amended (PUHCA). The Company is engaged predominantly in the generation and sale of electricity to wholesale and retail customers in South Carolina and in the purchase, sale and transportation of natural gas to retail customers in South Carolina.

The accompanying Consolidated Financial Statements reflect the accounts of SCE&G, South Carolina Fuel Company, Inc. (Fuel Company), South Carolina Generating Company, Inc, (GENCO) and SCE&G Trust I. Intercompany balances and transactions between SCE&G, Fuel Company, GENCO and SCE&G Trust I have been eliminated in consolidation.

The Company adopted Financial Accounting Standards Board Interpretation No. 46 (Revised 2003) (FIN 46), *"Consolidation of Variable Interest Entities",* effective January 1, 2004, which requires an enterprise's consolidated financial statements to include entities in which the enterprise has a controlling financial interest. SCE&G has determined that it has a controlling financial interest in GENCO under the criteria of FIN 46, and accordingly, the accompanying consolidated financial statements include the accounts of SCE&G, GENCO and Fuel Company. Prior period amounts have been restated to reflect the adoption of FIN 46. The consolidation resulted in an increase of approximately $327 million in net assets reflected in the consolidated balance sheet as of December 31, 2004. The equity interest in GENCO is held solely by SCANA Corporation, SCE&G's parent. Accordingly, GENCO's equity and results of operations are reflected as a minority interest in the Company's condensed consolidated financial statements, and the adoption of FIN 46 therefore had no impact on the Company's equity, net earnings or cash flows.

GENCO owns and operates a coal-fired electric generating station with a 615 megawatt net generating capacity (summer rating). GENCO's electricity is sold solely to SCE&G under the terms of a power purchase and related operating agreement. The effects of these transactions are eliminated in consolidation. Substantially all of GENCO's property (carrying value of approximately $80 million) serves as collateral for its long-term borrowings.

Affiliated Transactions

The Company has entered into agreements with certain affiliates to purchase all gas for resale to its distribution customers and to purchase electric energy. The Company purchases natural gas for resale and electric generation from South Carolina Pipeline Corporation (SCPC), and at December 31, 2004 and 2003, the Company had approximately $49.5 million and $39.5 million, respectively, payable to SCPC for such gas purchases.

In the fourth quarter 2004, the Company purchased approximately 186 miles of gas distribution pipeline from SCPC at their net book value, which totaled approximately $5.2 million.

Total interest income, based on market interest rates, associated with the Company's advances to affiliated companies in 2004 was not significant. In 2003 and 2002, such amounts were approximately $1.8 million and $0.4 million, respectively.

The Company purchases natural gas and related pipeline capacity to supply its Jasper County Electric Generating Station from SCANA Energy Marketing, Inc. (SEMI). Such purchases in 2004 totaled approximately $79.7 million and at December 31, 2004, SCE&G had approximately $4.5 million payable to SEMI for such purposes.

The Company holds two equity-method investments in partnerships involved in converting coal to non-conventional fuel. The Company had recorded as receivables from these affiliated companies for these investments approximately $18.6 million and $13.4 million at December 31, 2004 and 2003, respectively. The Company had recorded as payables to these affiliated companies totaling approximately $17.8 million and $12.2 million at December 31, 2004 and 2003, respectively. The Company purchased approximately $190.6 million, $145.2 million and $117.2 million of synthetic fuel from these affiliated companies in 2004, 2003 and 2002, respectively.

B. Basis of Accounting

The Company accounts for its regulated utility operations, assets and liabilities in accordance with the provisions of Statement of Financial Accounting Standards (SFAS) 71, *"Accounting for the Effects of Certain Types of Regulation."* SFAS 71 requires cost-based rate-regulated utilities to recognize in their financial statements certain revenues and expenses in different time periods than do enterprises that are not rate-regulated. As a result the Company has recorded, as of December 31, 2004, approximately $387 million and $551 million of regulatory assets (including environmental) and liabilities (including other asset retirement obligations), respectively, as shown below.

	December 31,	
	2004	2003
	Millions of dollars	
Accumulated deferred income taxes, net	$ 121	$ 104
Under- (over-) collections—electric fuel and gas cost adjustment clauses, net	31	13
Deferred purchased power costs	26	26
Deferred environmental remediation costs	11	11
Asset retirement obligation—nuclear decommissioning	49	48
Other asset retirement obligations	(363)	(265)
Deferred non-conventional fuel tax benefits, net	(97)	(67)
Storm damage reserve	(33)	(37)
Franchise agreements	58	62
Deferred regional transmission organization costs	14	—
Other	19	20
Total	$(164)	$ (85)

Accumulated deferred income tax liabilities arising from utility operations that have not been included in customer rates are recorded as a regulatory asset. Accumulated deferred income tax assets arising from deferred investment tax credits are recorded as a regulatory liability.

Under- (over-) collections—electric fuel and gas cost adjustment clauses, net represent amounts under-collected from customers pursuant to the fuel adjustment clause (electric customers) or gas cost adjustment (gas customers) as approved by the Public Service Commission of South Carolina (SCPSC) during annual hearings. See Note 1F.

Deferred purchased power costs represent costs that were necessitated by outages at two of SCE&G's base load generating plants in winter 2000-2001. The SCPSC approved recovery of these costs in base rates over a three year period beginning January 2005. See Note 2.

Deferred environmental remediation costs represent costs associated with the assessment and clean-up of manufactured gas plant (MGP) sites currently or formerly owned by SCE&G. Costs incurred by SCE&G at such sites are being recovered through rates. Such costs, totaling approximately $10.5 million, are expected to be fully recovered by the end of 2009.

Asset retirement obligation (ARO)—nuclear decommissioning represents the regulatory asset associated with the legal obligation to decommission and dismantle V. C. Summer Nuclear Station (Summer Station) as required in SFAS 143, *"Accounting for Asset Retirement Obligations."*

Other asset retirement obligations represent net collections through depreciation rates of estimated costs to be incurred for the future retirement of assets for which no legal retirement obligation exists.

Deferred non-conventional fuel tax benefits represent the deferral of partnership losses and other expenses of approximately $58.7 million, offset by the tax benefits of those losses and expenses and accumulated synthetic fuel tax credits of approximately $155.4 million, associated with SCE&G's two partnerships involved in converting coal to synthetic fuel. Under a plan approved by the SCPSC, any tax credits generated from non-conventional fuel produced by the partnerships and ultimately passed through to SCE&G, net of partnership losses and other expenses, have been and will be deferred and will be applied to offset the capital costs of constructing the back-up dam at Lake Murray. See Note 2.

The storm damage reserve represents an SCPSC approved reserve account capped at $50 million to be collected through rates. The accumulated storm damage reserve can be applied to offset actual incremental storm damage costs in excess of $2.5 million in a calendar year. For the year ended December 31, 2004, approximately $10.9 million had been drawn from this reserve account.

Franchise agreements represent costs associated with the 30-year electric and gas franchise agreements with the cities of Charleston and Columbia, South Carolina. These amounts are not earning a return, but are being amortized through cost of service over approximately 15 years.

Deferred regional transmission organization costs represent costs incurred by SCE&G in the United States Federal Energy Regulatory Commission (FERC)-mandated formation of GridSouth. The project was suspended in 2002. These amounts are not earning a return, however, in its January 2005 order the SCPSC approved SCE&G's request to amortize these costs over a five-year period. See Note 2.

The SCPSC has reviewed and approved through specific orders most of the items shown as regulatory assets. Other items represent costs which are not yet approved for recovery by the SCPSC. In recording these costs as regulatory assets, management believes the costs will be allowable under existing rate-making concepts that are embodied in rate orders received by the Company. However, ultimate recovery is subject to SCPSC approval. In the future, as a result of deregulation or other changes in the regulatory environment, the Company may no longer meet the criteria for continued application of SFAS 71 and could be required to write off its regulatory assets and liabilities. Such an event could have a material adverse effect on the Company's results of operations, liquidity or financial position in the period the write-off would be recorded.

C. System of Accounts

The accounting records of the Company are maintained in accordance with the Uniform System of Accounts prescribed by the FERC and as adopted by the SCPSC.

D. Utility Plant and Major Maintenance

Utility plant is stated substantially at original cost. The costs of additions, renewals and betterments to utility plant, including direct labor, material and indirect charges for engineering, supervision and an allowance for funds used during construction, are added to utility plant accounts. The original cost of utility property retired or otherwise disposed of is removed from utility plant accounts and generally charged to accumulated depreciation. The costs of repairs, replacements and renewals of items of property determined to be less than a unit of property or that do not increase the asset's life or functionality are charged to maintenance expense.

The Company, operator of Summer Station, and the South Carolina Public Service Authority (Santee Cooper) are joint owners of Summer Station in the proportions of two-thirds and one-third, respectively. The parties share the operating costs and energy output of the plant in these proportions. Each party, however, provides its own financing. Plant-in-service related to the Company's portion of Summer Station was approximately $1.0 billion as of December 31, 2004 and 2003 (including amounts related to ARO). Accumulated depreciation associated with the Company's share of Summer Station was approximately $463.7 million and $449.5 million as of December 31, 2004 and 2003 (including amounts related to ARO). The Company's share of the direct expenses associated with operating Summer Station is included in "Other operation and maintenance" expenses and totaled approximately $74.4 million, $74.7 million and $76.4 million for the years ended December 31, 2004, 2003 and 2002, respectively.

Planned major maintenance other than that related to nuclear outages is expensed when incurred. The only major maintenance that is accrued in advance of the time the costs are actually incurred is that related to nuclear refueling outages for which such accounting treatment and rate recovery of expenses accrued thereunder has been approved by the SCPSC. Nuclear outages are scheduled 18 months apart, and the Company begins accruing for each successive outage upon completion of the preceding outage. The Company is accruing approximately $0.8 million per month from January 2004 through June 2005 for its portion of the outage scheduled to begin April 2005. Total costs for the 2005 planned outage are estimated to be approximately $22.2 million, of which the Company will be responsible for approximately $14.8 million. As of December 31, 2004 and 2003, SCE&G had accrued approximately $9.9 million and $7.5 million.

E. Allowance for Funds Used During Construction (AFC)

AFC is a noncash item that reflects the period cost of capital devoted to plant under construction. This accounting practice results in the inclusion of, as a component of construction cost, the costs of debt and equity capital dedicated to construction investment. AFC is included in rate base investment and depreciated as a component of plant cost in establishing rates for utility services. The Company has calculated AFC using composite rates of 6.7%, 7.8% and 7.9% for 2004, 2003 and 2002, respectively. These rates do not exceed the maximum allowable rate as calculated under FERC Order No. 561. Interest on nuclear fuel in process is capitalized at the actual interest amount incurred.

F. Revenue Recognition

Revenues are recorded during the accounting period in which services are provided to customers and include estimated amounts for electricity and natural gas delivered but not yet billed. Unbilled revenues totaled approximately $48.1 million and $50 million as of December 31, 2004 and 2003, respectively.

Fuel costs for electric generation are collected through the fuel cost component in retail electric rates. The fuel cost component contained in electric rates is established by the SCPSC during annual fuel cost hearings. Any difference between actual fuel costs and amounts contained in the fuel cost component is deferred and included when determining the fuel cost component during the next annual fuel cost hearing. The Company had undercollected through the electric fuel cost component approximately $19.6 million and $1.1 million at December 31, 2004 and 2003, respectively, which amounts are included in other regulatory assets.

Customers subject to the gas cost adjustment clause are billed based on a fixed cost of gas determined by the SCPSC during annual gas cost recovery hearings. Any difference between actual gas costs and amounts contained in rates is deferred and included when establishing gas costs during the next annual gas cost recovery hearing. At December 31, 2004 and 2003 the Company had undercollected approximately $11.1 million and $11.9 million, respectively, which amounts are also included in other regulatory assets.

The Company's gas rate schedules for residential, small commercial and small industrial customers include a weather normalization adjustment which minimizes fluctuations in gas revenues due to abnormal weather conditions.

G. Depreciation and Amortization

Provisions for depreciation and amortization are recorded using the straight-line method and are based on the estimated service lives of the various classes of property. The composite weighted average depreciation rates for utility plant assets were 2.97%, 3.00% and 2.92% for 2004, 2003 and 2002, respectively.

Nuclear fuel amortization, which is included in "Fuel used in electric generation" and recovered through the fuel cost component of the Company's rates, is recorded using the units-of-production method. Provisions for amortization of nuclear fuel include amounts necessary to satisfy obligations to the Department of Energy (DOE) under a contract for disposal of spent nuclear fuel.

H. Nuclear Decommissioning

The Company's two-thirds share of estimated site-specific nuclear decommissioning costs for Summer Station, including the cost of decommissioning plant components not subject to radioactive contamination, totals approximately $357.3 million, stated in 1999 dollars, based on a decommissioning study completed in 2000. Santee Cooper is responsible for decommissioning costs related to its one-third ownership interest in Summer Station. The cost estimate is based on a decommissioning methodology acceptable to the Nuclear Regulatory Commission (NRC) under which the site would be maintained over a period of approximately 60 years in such a manner as to allow for subsequent decontamination that permits release for unrestricted use. The Company records its liability for decommissioning cost in deferred credits.

Under the Company's method of funding decommissioning costs, funds collected through rates ($3.2 million in each of 2004, 2003 and 2002) are invested in insurance policies on the lives of certain Company and affiliate personnel. The Company is the beneficiary of the policies. Through these insurance contracts, the Company is able to take advantage of income tax benefits and accrue earnings on a tax-deferred basis. Amounts for decommissioning collected through electric rates, insurance proceeds, and interest on proceeds, less expenses, are transferred by the Company to an external trust fund. Management intends for the fund, including earnings thereon, to provide for all eventual decommissioning expenditures on an after-tax basis.

In addition to the above, pursuant to the National Energy Policy Act passed by Congress in 1992 and the requirements of the DOE, the Company has recorded a liability for its estimated share of the DOE's decontamination and decommissioning obligation. The liability, approximately $1.1 million and $1.5 million at December 31, 2004 and 2003, respectively, has been included in "Long-Term Debt, net." The Company is recovering the cost associated with this liability through the fuel cost component of its rates; accordingly, this amount has been deferred and is included in other regulatory assets.

I. Income and Other Taxes

The Company is included in the consolidated federal income tax return of SCANA. Under a joint consolidated income tax allocation agreement, each subsidiary's current and deferred tax expense is computed on a stand-alone basis. Deferred tax assets and liabilities are recorded for the tax effects of all significant temporary differences between the book basis and tax basis of assets and liabilities at currently enacted tax rates. Deferred tax assets and liabilities are adjusted for changes in such rates through charges or credits to regulatory assets or liabilities if they are expected to be recovered from, or passed through to, customers; otherwise, they are charged or credited to income tax expense. Also under provisions of the income tax allocation agreement, certain tax benefits of the parent holding company are distributed in cash to tax paying affiliates, including the Company, in the form of capital contributions. In 2003 capital contributions of approximately $8.5 million were received by the Company under such provisions. In 2004, based upon a true-up of the parent's tax benefit, the Company returned approximately $2.9 million in capital contributions received in 2003.

The Company records excise taxes billed and collected, as well as local franchise and similar taxes, as liabilities until they are remitted to the respective taxing authority. As such, no excise taxes are included in revenues or expenses in the statements of income.

J. Debt Premium, Discount and Expense, Unamortized Loss on Reacquired Debt

Long-term debt premium and discount are recorded in long-term debt and are being amortized as components of Interest Charges over the terms of the respective debt issues. Other issuance expense and gains or losses on reacquired debt that is refinanced are recorded in other deferred debits or credits and amortized over the term of the replacement debt.

K. Environmental

The Company maintains an environmental assessment program to identify and evaluate current and former operations sites that could require environmental cleanup. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and clean up each site. These estimates are refined as additional information becomes available; therefore, actual expenditures could differ significantly from the original estimates. Amounts estimated and accrued to date for site assessments and cleanup relate solely to regulated operations. Such amounts are recorded in deferred debits and amortized with recovery provided through rates.

L. Fuel Inventories

Nuclear fuel and fossil fuel inventories and sulfur dioxide emission allowances are purchased and financed by Fuel Company under a contract which requires SCE&G to reimburse Fuel Company for all costs and expenses relating to the ownership and financing of fuel inventories and sulfur dioxide emission allowances. Accordingly, such fuel inventories and emission allowances and fuel-related assets and liabilities are included in the Company's consolidated financial statements. See Note 5.

M. Cash and Cash Equivalents

The Company considers temporary cash investments having original maturities of three months or less to be cash equivalents. These cash equivalents are generally in the form of commercial paper, certificates of deposit and repurchase agreements.

N. New Accounting Standard

SFAS 153, "*Exchanges of Nonmonetary Assets*," was issued in December 2004 and amends APB 29, "*Accounting for Nonmonetary Transactions*." SFAS 153 makes a general exception from fair value measurement for exchanges of nonmonetary assets that do not have commercial substance. A nonmonetary exchange has commercial substance if the future cash flows of the entity are expected to change significantly as a result of the exchange. SFAS 153 applies prospectively to nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. The Company does not expect that the initial adoption of SFAS 153 will have a material impact on the Company's results of operations, cash flows or financial position.

O. Reclassifications

Certain amounts from prior periods have been reclassified to conform with the presentation adopted for 2004.

P. Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amount of revenues and expenses during the reporting period. Actual results could differ from those estimates.

2. RATE AND OTHER REGULATORY MATTERS

Electric

In a January 2005 order the SCPSC granted SCE&G a composite increase in retail electric rates of approximately 2.89%, designed to produce additional annual revenues of approximately $41.4 million based on a test year calculation. The SCPSC lowered SCE&G's return on common equity from 12.45% to a range of between 10.4% and 11.4%, with rates to be set at 10.7%. The new rates became effective in January 2005. As a part of its order, the SCPSC approved SCE&G's recovery of construction and operating costs for SCE&G's new Jasper County Electric Generating Station, recovery of costs of mandatory environmental upgrades primarily related to Federal Clean Air Act regulations and the application of current and anticipated net synthetic fuel tax credits to offset the cost of constructing the back-up dam at Lake Murray. The SCPSC also approved recovery over a five-year period of SCE&G's approximately $14 million of costs incurred in the formation of the GridSouth Regional Transmission Organization and recovery through base rates over three years of approximately $25.6 million of purchased power costs that were previously deferred. As a part of its order, the SCPSC extended through 2010 its approval of the accelerated capital recovery plan for SCE&G's Cope Generating Station. Under the plan, based on the level of revenues and operating expenses, SCE&G may increase depreciation of its Cope Generating Station in excess of amounts that would be recorded based upon currently approved depreciation rates, not to exceed $36 million annually, without additional approval of the SCPSC. Any unused portion of the $36 million in any given year may be carried forward for possible use in the following year.

In January 2003 the SCPSC granted SCE&G a composite increase in retail electric rates of approximately 5.8% designed to produce additional annual revenues of approximately $70.7 million based on a test year calculation. The SCPSC authorized a return on common equity of 12.45%. The rates and authorized return were effective for service rendered on and after February 1, 2003 until January 2005.

SCE&G's rates are established using a cost of fuel component approved by the SCPSC which may be modified periodically to reflect changes in the price of fuel purchased by SCE&G. SCE&G's cost of fuel component in effect during 2004 and 2003 was as follows:

Rate Per KWh	Effective Date
$1.722	January 2003
$1.678	February 2003-April 2004
$1.821	May-December 2004

Gas

The Company's rates are established using a cost of gas component approved by the SCPSC which may be modified periodically to reflect changes in the price of natural gas purchased by the Company. The Company's cost of gas component in effect during 2004 and 2003 was as follows:

Rate Per Therm	Effective Date
$.728	January-February 2003
$.928	March-October 2003
$.877	November 2003-October 2004
$.903	November-December 2004

The SCPSC allows the Company to recover, through a billing surcharge to its gas customers, the costs of environmental cleanup at the sites of former MGPs. The billing surcharge is subject to annual review and provides for the recovery of substantially all actual and projected site assessment and cleanup costs and environmental claims settlements for the Company's gas operations that had previously been recorded in deferred debits. In October 2003, as a result of the annual review, the SCPSC approved the Company's request to reduce the billing surcharge from 3.0 cents per therm to 0.8 cents per therm, which is intended to provide for the recovery, prior to the end of the year 2009, of the balance remaining at December 31, 2004 of $10.5 million.

3. EMPLOYEE BENEFIT PLANS

The Company participates in SCANA's noncontributory defined benefit pension plan, which covers substantially all permanent employees. The Company's policy has been to fund the plan to the extent permitted by federal income tax regulations as determined by an independent actuary.

Effective July 1, 2000 SCANA's pension plan was amended to provide a cash balance formula. With certain exceptions employees were allowed to either remain under the final average pay formula or elect the cash balance formula. Under the final average pay formula, benefits are based on years of credited service and the employee's average annual base earnings received during the last three years of employment. For employees electing the cash balance formula, the monthly benefit earned under the final average pay formula at July 1, 2000 was converted to a lump sum amount and increased by transition credits for eligible employees. This opening balance increases going forward as a result of compensation credits and interest credits.

In addition to pension benefits, the Company participates in SCANA's unfunded postretirement health care and life insurance programs which provide benefits to active and retired employees. Retirees share in a portion of their medical care cost. The Company provides life insurance benefits to retirees at no charge. The costs of postretirement benefits other than pensions are accrued during the years the employees render the services necessary to be eligible for the applicable benefits.

The measurement date used to determine pension and other postretirement benefit obligations is December 31. Information regarding the benefit obligations and the funding thereof is presented below.

Changes in Benefit Obligations

Data related to the changes in the projected benefit obligation for retirement benefits and the accumulated benefit obligation for other postretirement benefits are presented below.

	Retirement Benefits		Other Postretirement Benefits	
	2004	2003	2004	2003
	Millions of dollars			
Benefit obligation, January 1	$619.9	$595.6	$188.4	$183.4
Service cost	11.1	9.5	3.3	2.7
Interest cost	37.4	36.7	11.4	11.4
Plan participants' contributions	—	—	1.1	0.8
Plan amendments	8.0	—	4.7	—
Actuarial loss	24.1	7.6	1.2	4.3
Benefits paid	(31.0)	(29.5)	(12.6)	(14.2)
Benefit obligation, December 31	$669.5	$619.9	$197.5	$188.4

The accumulated benefit obligation for retirement benefits at the end of 2004 and 2003 was $635.8 million and $589.8 million, respectively. These accumulated retirement benefit obligations differ from the projected retirement benefit obligations above in that they reflect no assumptions about future compensation levels.

Significant assumptions used to determine the above benefit obligations are as follows:

	2004	2003
Annual discount rate used to determine benefit obligations	5.75%	6.00%
Assumed annual rate of future salary increases for projected benefit obligation	4.00%	4.00%

A 9.0% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2004. The rate was assumed to decrease gradually to 5.0% for 2011 and to remain at that level thereafter. The effects of a one-percentage-point increase or decrease on accumulated other postretirement benefit obligation for health care benefits are as follows:

	1% Increase	1% Decrease
	Millions of dollars	
Effect on postretirement benefit obligation	$4.0	$(3.5)

In December 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the "Act") was enacted. The Act established a prescription drug benefit under Medicare, known as "Medicare Part D," and a federal subsidy to sponsors of retiree health care benefit plans that provide a prescription drug benefit that is at least actuarially equivalent to Medicare Part D. The Company anticipates that benefits provided to some groups of plan participants will be actuarially equivalent to Medicare Part D and therefore will entitle the Company to a federal subsidy.

In May 2004, the FASB issued FASB Staff Position No. FAS 106-2, *"Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act"* ("FSP 106-2"). FSP 106-2 provides definitive guidance on the recognition of the effects of the Act and related disclosure requirements for employers that sponsor prescription drug benefit plans for retirees. In the quarter beginning July 1, 2004 the Company adopted FSP 106-2. The expected subsidy reduced the accumulated postretirement benefit obligation (APBO) as of July 1, 2004 by $3.7 million, and net periodic cost for 2004 by $0.2 million, as compared to the amount calculated without considering the effects of the subsidy.

Changes in Plan Assets

	Retirement Benefits	
	2004	2003
	Millions of dollars	
Fair value of plan assets, January 1	$787.7	$666.9
Actual return on plan assets	90.0	150.3
Benefits paid	(31.0)	(29.5)
Fair value of plan assets, December 31	$846.7	$787.7

At the end of 2004 and 2003, the fair value of plan assets for the pension plan exceeded both the projected benefit obligation and the accumulated benefit obligation discussed above. Since the accumulated benefit obligation is less than the fair value of plan assets, there is no adjustment to other comprehensive income.

Funded Status of Plans

	Retirement Benefits		Other Postretirement Benefits	
	2004	2003	2004	2003
	Millions of dollars			
Funded status, December 31	$177.2	$167.8	$(197.5)	$(188.4)
Unrecognized actuarial loss	28.2	23.1	44.2	45.0
Unrecognized prior service cost	78.3	76.8	6.4	2.9
Unrecognized net transition obligation	1.4	2.3	5.0	5.9
Net asset (liability) recognized in consolidated balance sheet	$285.1	$270.0	$(141.9)	$(134.6)

In connection with the joint ownership of Summer Station, as of December 31, 2004 and 2003 the Company recorded within deferred credits a $9.7 million and $9.3 million obligation, respectively, to Santee Cooper, representing an estimate of the net pension asset attributable to the Company's contributions to the pension plan that were recovered through billings to Santee Cooper for its one-third portion of shared costs. As of December 31, 2004 and 2003, the Company also recorded a $6.8 million and $6.5 million receivable, respectively, from Santee Cooper, representing an estimate of its portion of the unfunded net postretirement benefit obligation.

Expected Cash Flows

The total benefits expected to be paid from the pension plan or from the Company's assets for the pension and other postretirement benefits plans, respectively, are as follows:

Expected Benefit Payments Millions of dollars	Pension Benefits	Other Postretirement Benefits*
2005	$ 41.8	$13.4
2006	44.2	13.9
2007	44.7	14.0
2008	49.2	13.9
2009	49.9	14.0
2010-2014	287.0	73.9

* Net of participant contributions

Net Periodic Cost

As allowed by SFAS 87 and SFAS 106, the Company records net periodic benefit cost (income) utilizing beginning of the year assumptions. Disclosures required for these plans under SFAS 132, "Employer's Disclosures about Pensions and Other Postretirement Benefits," are set forth in the following tables:

Components of Net Periodic Benefit Cost (Income)

	Retirement Benefits			Other Postretirement Benefits		
	2004	2003	2002	2004	2003	2002
	Millions of dollars					
Service cost	$ 11.1	$ 9.5	$ 9.0	$ 3.3	$ 2.7	$ 3.1
Interest cost	37.4	36.7	39.8	11.4	11.4	12.4
Expected return on assets	(71.0)	(59.9)	(77.6)	n/a	n/a	n/a
Prior service cost amortization	6.6	6.3	6.3	1.4	0.9	0.9
Actuarial (gain) loss	—	1.6	(4.1)	1.9	1.5	1.1
Transition amount amortization	0.8	0.8	0.8	0.8	0.8	0.8
Amount attributable to Company affiliates	(1.7)	(1.8)	0.3	(5.4)	(5.0)	(5.3)
Net periodic benefit (income) cost	$(16.8)	$ (6.8)	$(25.5)	$13.4	$12.3	$13.0

Significant Assumptions Used in Determining Net Periodic Benefit Cost (Income)

	Retirement Benefits			Other Postretirement Benefits		
	2004	2003	2002	2004	2003	2002
Discount rate	6.00%	6.50%	7.50%	6.00%	6.50%	7.50%
Expected return on plan assets	9.25%	9.25%	9.50%	n/a	n/a	n/a
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
Health care cost trend rate	n/a	n/a	n/a	9.50%	10.00%	8.50%
Ultimate health care cost trend rate	n/a	n/a	n/a	5.00%	5.00%	5.00%
Year achieved	n/a	n/a	n/a	2011	2011	2009
Measurement date	Jan 1	Jan 1	Jan 1	Jan 1	Jan 1	Jan 1

The effect of a one-percentage-point increase or decrease in the assumed health care cost trend rate on total service and interest cost is less than $250,000.

Pension Plan Contributions

While the investment performance over the 2000-2002 period and the recent decline in discount rates have significantly reduced the level of pension income, the pension trust has been and remains adequately funded. No contributions have been required since 1997, and the Company does not anticipate making contributions to the funded pension plan in 2005. As such, these declines in pension income have had no impact on the Company's cash flows.

Pension Plan Asset Allocations

The Company's pension plan asset allocation at December 31, 2004 and 2003 and the target allocations for 2005 are as follows:

Asset Category	Target Allocation	Percentage of Plan Assets At December 31	
		2004	2003
Equity Securities	70%	72%	71%
Debt Securities	30%	28%	29%

The assets of the pension plan are invested in accordance with the objectives of (1) fully funding the actuarial accrued liability for the pension plan (Plan), (2) maximizing return within reasonable and prudent levels of risk in order to minimize contributions, and (3) maintaining sufficient liquidity to meet benefits payment obligations on a timely basis. These objectives have been based on a ten-year investment horizon, so that interim fluctuations should be viewed with appropriate perspective. The pension plan operates with several risk and control procedures including a review of liabilities, investment objectives, investment managers and performance expectations. Transactions involving certain types of investments are prohibited. Equity securities held by the pension plan during the above periods did not include SCANA common stock.

In developing the expected long-term rate of return assumptions, management evaluates the pension plan's historical cumulative actual returns over several periods, which have all been in excess of related broad indices. Management anticipates that the pension plan's investment managers will continue to generate long-term returns of at least 9.25%. The expected long-term rate of return of 9.25% assumes an asset allocation of 70% with equity managers and 30% with fixed income managers. Management regularly reviews such allocations and periodically rebalances the portfolio to the targeted allocation when considered appropriate.

4. LONG-TERM DEBT

Long-term debt by type with related weighted average interest rates and maturities is as follows:

	Weighted-Average Rate	Year Due	December 31, 2004	December 31, 2003
			Millions of dollars	
First Mortgage Bonds (secured)	6.25%	2005-2033	$1,700	$1,800
First & Refunding Mortgage Bonds (secured)	9.00%	2006	131	131
GENCO Notes (secured)	6.02%	2011-2024	130	34
Industrial and Pollution Control Bonds	5.24%	2012-2032	156	156
Other		2005-2009	81	51
Total debt			2,198	2,172
Current maturities of long-term debt			(198)	(142)
Unamortized Discount			(19)	(20)
Total long-term debt, net			$1,981	$2,010

The annual amounts of long-term debt maturities and sinking fund requirements for the years 2005 through 2009 are summarized as follows:

Year	Amount	Year	Amount
	(Millions of dollars)		
2005	$195	2008	$ 45
2006	176	2009	145
2007	45		

Approximately $35.5 million of the long-term debt maturing in 2005 relates to a sinking fund requirement which may be satisfied by either deposit and cancellation of bonds issued upon the basis of property additions or bond retirement credits, or by deposit of cash with the Trustee.

In 2004 the Company borrowed $35.4 million under an agreement with the South Carolina Transportation Infrastructure Bank (the Bank) and the South Carolina Department of Transportation (SCDOT) that allows the Company to borrow funds from the Bank to construct a roadbed for SCDOT in connection with the Lake Murray Dam remediation project. The loan agreement provides for interest-free borrowings of up to $59 million, with such borrowings being repaid over ten years from the initial borrowing. At December 31, 2004 the Company had $32.5 million outstanding under the agreement.

Substantially all utility plant is pledged as collateral in connection with long-term debt. The Company is in compliance with all debt covenants.

5. LINES OF CREDIT AND SHORT-TERM BORROWINGS

Details of lines of credit and short-term borrowings at December 31, 2004 and 2003, are as follows:

	2004	2003
	Millions of dollars	
Lines of credit (total and unused)		
Committed	$ 525	$ 475
Uncommitted(1)	113[(1)]	113[(1)]
Short-term borrowings outstanding		
Commercial paper (270 or fewer days)	$152.9	$140.1
Weighted average interest rate	2.40%	1.15%

(1) Lines of credit that either the Company or SCANA may use.

The Company pays fees to banks as compensation for maintaining committed lines of credit.

Nuclear and fossil fuel inventories and certain emission allowances are financed through the issuance by Fuel Company of short-term commercial paper. All commercial paper borrowings are supported by five-year revolving credit facilities which expire on June 15, 2009. The committed credit facilities provide for a maximum amount of $525 million to be outstanding at any time.

Fuel Company commercial paper outstanding totaled $31.3 million and $45.7 million at December 31, 2004 and 2003, respectively, at weighted average interest rates of 2.44% and 1.15%, respectively.

SCE&G's commercial paper outstanding totaled $121.6 million and $94.4 million at December 31, 2004 and 2003, respectively, at weighted average interest rates of 2.39% and 1.15%, respectively.

6. RETAINED EARNINGS

The Company's Restated Articles of Incorporation contain provisions that, under certain circumstances, which the Company considers to be remote, could limit the payment of cash dividends on its common stock. In addition, with respect to hydroelectric projects, the Federal Power Act requires the appropriation of a portion of certain earnings therefrom. At December 31, 2004 approximately $48 million of retained earnings were restricted by this requirement as to payment of cash dividends on common stock.

7. PREFERRED STOCK

Retirements under sinking fund requirements are at par values. The aggregate of the annual amounts of purchase fund or sinking fund requirements for preferred stock for the years 2005 through 2009 is $2.7 million. The call premium of the respective series of preferred stock in no case exceeds the amount of the annual dividend. At December 31, 2004 the Company had shares of preferred stock authorized and available for issuance as follows:

Par Value	Authorized	Available for Issuance
$100	1,000,000	—
$ 50	609,688	300,000
$ 25	2,000,000	2,000,000

Preferred Stock (Not Subject to purchase or sinking funds)

For each of the three years ended December 31, 2004 SCE&G had outstanding 1,000,000 shares of 6.52% $100 par and 125,209 shares of 5.00% $50 par Cumulative Preferred Stock (not subject to purchase or sinking funds).

Preferred Stock (Subject to purchase or sinking funds)

Changes in "Total Preferred Stock (Subject to purchase or sinking funds)" during 2004, 2003 and 2002 are summarized as follows:

	Series			
	4.50%, 4.60% (A) & 5.125%	4.60% (B) & 6.00%		Millions
Redemption Price	$51.00	$50.50	Total Shares	of Dollars
Balance at December 31, 2001 . . .	88,449	121,035	209,484	$10.5
Shares Redeemed—$50 par value	(4,600)	(4,911)	(9,511)	(0.5)
Balance at December 31, 2002 . . .	83,849	116,124	199,973	10.0
Shares Redeemed—$50 par value	(2,815)	(3,563)	(6,378)	(0.3)
Balance at December 31, 2003 . . .	81,034	112,561	193,595	9.7
Shares Redeemed—$50 par value	(2,516)	(6,600)	(9,116)	(0.5)
Balance at December 31, 2004 . . .	78,518	105,961	184,479	$ 9.2

In 1997 SCE&G Trust I (the "Trust"), a wholly owned subsidiary of SCE&G, issued $50 million of 7.55% Trust Preferred Securities, Series A. In 2003 SCE&G effected the redemption of those securities.

8. INCOME TAXES

Total income tax expense attributable to income (before cumulative effect of accounting change) for 2004, 2003 and 2002 is as follows:

	2004	2003	2002
	Millions of dollars		
Current taxes:			
Federal	$ 47.4	$ 23.7	$ 64.3
State	(4.4)	8.5	8.8
Total current taxes	43.0	32.2	73.1
Deferred taxes, net:			
Federal	28.1	41.7	11.9
State	4.1	0.7	1.9
Total deferred taxes	32.2	42.4	13.8
Investment tax credits:			
Deferred—State	10.0	5.0	5.0
Amortization of amounts deferred—State	(2.1)	(1.8)	(1.6)
Amortization of amounts deferred—Federal	(3.6)	(3.6)	(3.6)
Total investment tax credits	4.3	(0.4)	(0.2)
Non-conventional fuel tax credits:			
Deferred—Federal	40.5	35.7	29.8
Total income tax expense	$120.0	$109.9	$116.5

The difference between actual income tax expense and that amount calculated from the application of the statutory 35% federal income tax rate to pre-tax income (before cumulative effect of accounting change) is reconciled as follows:

	2004	2003	2002
	Millions of dollars		
Income before cumulative effect of accounting change	$235.5	$221.1	$217.6
Income tax expense	120.0	109.9	116.5
Preferred stock dividends	7.3	9.1	11.2
Total pre-tax income	362.8	$340.1	$345.3
Income taxes on above at statutory federal income tax rate	$127.0	$119.0	$120.9
Increases (decreases) attributed to:			
State income taxes (less federal income tax effect)	4.9	8.0	9.2
Allowance for equity funds used during construction	(5.0)	(6.2)	(7.0)
Amortization of federal investment tax credits	(3.6)	(3.6)	(3.6)
Other differences, net	(3.3)	(7.3)	(3.0)
Total income tax expense	$120.0	$109.9	$116.5

The tax effects of significant temporary differences comprising the Company's net deferred tax liability of $759.0 million at December 31, 2004 and $715.5 million at December 31, 2003 (see Note 1I) are as follows:

	2004	2003
	Millions of dollars	
Deferred tax assets:		
Nondeductible reserves	$ 68.8	$ 63.0
Unamortized investment tax credits	59.9	58.7
Deferred compensation	22.0	22.1
Federal alternative minimum tax credit carryforward	12.3	—
Other	12.6	15.4
Total deferred tax assets	175.6	159.2
Deferred tax liabilities:		
Property, plant and equipment	789.5	748.5
Pension plan benefit income	102.4	94.4
Deferred fuel costs	21.6	14.8
Other	21.1	17.0
Total deferred tax liabilities	934.6	874.7
Net deferred tax liability	$759.0	$715.5

The Internal Revenue Service has completed and closed examinations of the Company's consolidated federal income tax returns through tax years ending in 2000. The IRS has also closed the examination of S. C. Coaltech No. 1 L.P., a synthetic fuel partnership in which the Company has an interest, for the 2000 tax year, resulting in that return being accepted as filed. The Company continues to believe that all of its synthetic fuel tax credits have been properly claimed.

9. FINANCIAL INSTRUMENTS

The carrying amounts and estimated fair values of the Company's financial instruments at December 31, 2004 and 2003 are as follows:

	2004		2003	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	Millions of dollars			
Assets:				
Cash and cash equivalents	$ 19.9	$ 19.9	$ 55.4	$ 55.4
Investments	6.3	6.3	5.7	5.7
Liabilities:				
Short-term borrowings	152.9	152.9	140.1	140.1
Long-term debt	2,179.4	2,347.6	2,081.8	2,192.7
Preferred stock (subject to purchase or sinking funds)	9.2	8.5	9.7	8.8

The following methods and assumptions were used to estimate the fair value of financial instruments:

- Cash and cash equivalents, which may include commercial paper, certificates of deposits, repurchase agreements, treasury bills and notes, are valued at their carrying amount.

- Fair values of investments and long-term debt are based on quoted market prices of the instruments or similar instruments. For debt instruments for which no quoted market prices are available, fair values are based on net present value calculations. For investments for which the fair value is not readily determinable, fair value is considered to approximate carrying value. Early settlement of long-term debt may not be possible or may not be considered prudent.
- Short-term borrowings are valued at their carrying amount.
- The fair value of preferred stock (subject to purchase or sinking funds) is estimated using market prices.
- Potential taxes and other expenses that would be incurred in an actual sale or settlement have not been considered.
- In anticipation of the issuance of debt, the Company also uses interest rate lock or similar agreements to manage interest rate risk. Payments received or made upon termination of such agreements are recorded within other deferred debits on the balance sheet and are amortized to interest expense over the term of the underlying debt. In connection with the issuance of First Mortgage Bonds in May 2003, the Company paid approximately $11.9 million upon the termination of a treasury lock agreement. In connection with the issuance of First Mortgage Bonds on December 2003, the Company paid approximately $3.5 million upon the termination of a forward starting interest rate swap.

10. COMMITMENTS AND CONTINGENCIES:

A. Lake Murray Dam Reinforcement

In 2001 the Company began construction to reinforce its Lake Murray Dam in order to comply with new federal safety standards mandated by FERC. Construction for the project and related activities is expected to cost approximately $275 million (excluding AFC) and be completed in 2005. Costs incurred through December 31, 2004 totaled approximately $240 million.

B. Nuclear Insurance

The Price-Anderson Indemnification Act (the Act) deals with public liability for a nuclear incident. Though the Act expired in 2003, existing licensees, such as the Company, are "grandfathered" under the Act until such time as it is renewed. The Act establishes the liability limit for third-party claims associated with any nuclear incident at $10.8 billion. Each reactor licensee is currently liable for up to $100.6 million per reactor owned for each nuclear incident occurring at any reactor in the United States, provided that not more than $10 million of the liability per reactor would be assessed per year. SCE&G's maximum assessment, based on its two-thirds ownership of Summer Station, would be approximately $67.1 million per incident, but not more than $6.7 million per year.

The Company currently maintains policies (for itself and on behalf of Santee Cooper) with Nuclear Electric Insurance Limited. The policies, covering the nuclear facility for property damage, excess property damage and outage costs, permit retrospective assessments under certain conditions to cover insurer's losses. Based on the current annual premium, the Company's portion of the retrospective premium assessment would not exceed $15.8 million.

To the extent that insurable claims for property damage, decontamination, repair and replacement and other costs and expenses arising from a nuclear incident at Summer Station exceed the policy limits of insurance, or to the extent such insurance becomes unavailable in the future, and to the extent that SCE&G's rates would not recover the cost of any purchased replacement power, the Company will retain the risk of loss as a self-insurer. The Company has no reason to anticipate a serious nuclear incident at Summer Station. If such an incident were to occur, it would have a material adverse impact on the Company's results of operations, cash flows and financial position.

C. Environmental

At the Company, site assessment and cleanup costs are deferred and amortized with recovery provided through rates. Deferred amounts, net of amounts previously recovered through rates and insurance settlements, totaled $10.5 million at December 31, 2004. The deferral includes the estimated costs associated with the following matters.

The Company owns a decommissioned MGP site in the Calhoun Park area of Charleston, South Carolina. The site is currently being remediated for contamination. The Company anticipates that the remaining remediation activities will be completed by the end of 2005, with certain monitoring and other activities continuing until 2010. As of December 31, 2004, the Company has spent approximately $20.5 million to remediate the Calhoun Park site, and expects to spend an additional $1.3 million. In addition, SCE&G is party to certain claims for cost and damages from this site, for which claims the National Park Service of the Department of the Interior made an initial demand for payment of approximately $9 million. Any costs arising from these matters are expected to be recoverable through rates under South Carolina regulatory processes.

The Company owns three other decommissioned MGP sites in South Carolina which contain residues of by-product chemicals. One of the sites has been remediated and will undergo routine monitoring until released by DHEC. The other two sites are currently being investigated under work plans approved by DHEC. The Company anticipates that major remediation activities for the three sites will be completed in 2010. As of December 31, 2004, the Company has spent approximately $4 million related to these three sites, and expects to spend an additional $4 million.

D. Franchise Agreements

See Note 1B for a discussion of the electric and gas franchise agreements between the Company and the cities of Columbia and Charleston.

E. Claims and Litigation

On August 21, 2003, the Company was served as a co-defendant in a purported class action lawsuit styled as Collins v. Duke Energy Corporation, Progress Energy Services Company, and South Carolina Electric & Gas Company, in South Carolina's Circuit Court of Common Pleas for the Fifth Judicial Circuit. The plaintiffs are seeking damages for the alleged improper use of electric transmission and distribution easements but have not asserted a dollar amount for their claims. Specifically, the plaintiffs contend that the licensing of attachments on electric utility poles, towers and other facilities to non-utility third parties or telecommunication companies for other than the electric utilities' internal use along the electric transmission line right-of-way constitutes a trespass. The Company is confident of the propriety of the Company's actions and intends to mount a vigorous defense. The Company further believes that the resolution of these claims will not have a material adverse impact on its results of operations, cash flows or financial condition.

On May 17, 2004, the Company was served with a purported class action lawsuit styled as Douglas E. Gressette, individually and on behalf of other persons similarly situated, v. South Carolina Electric & Gas Company and SCANA Corporation. The case was filed in South Carolina's Circuit Court of Common Pleas for the Ninth Judicial Circuit. The plaintiff alleges the Company made improper use of certain easements and rights-of-way by allowing fiber optic communication lines and/or wireless communication apparatuses to transmit communications other than the Company's electricity-related internal communications. The plaintiff asserts causes of action for unjust enrichment, trespass, injunction and declaratory judgment. The plaintiff did not assert a specific dollar amount for the claims. The Company believes its actions are consistent with governing law and the applicable documents granting easements and rights-of-way. The Company intends to mount a vigorous defense and believes that the resolution of these claims will not have a material adverse impact on its results of operations, cash flows or financial condition.

A complaint was filed on October 22, 2003 against the Company by the State of South Carolina alleging that the Company violated the Unfair Trade Practices Act by charging municipal franchise fees to some customers residing outside a municipality's limits. The complaint alleged that the Company failed to obey, observe or comply with the lawful order of the SCPSC by charging franchise fees to those not residing within a municipality. The complaint sought restitution to all affected customers and penalties up to $5,000 for each separate violation. The State of South Carolina v. SCE&G has been settled by an agreement between the parties, and the settlement has been approved by the court. The allegations are also the subject of a purported class action lawsuit filed in December 2003, against Duke Energy Corporation, Progress Energy Services Company and SCE&G (styled Edwards v. SCE&G). Duke Energy and Progress Energy have been voluntarily dismissed from the Edwards lawsuit. The Company believes that the resolution of these actions will not have a material adverse impact on its results of operations, cash flows or financial condition. In addition, the Company filed a petition with the SCPSC on October 23, 2003 pursuant to S. C. Code Ann. R.103-836. The petition requests that the SCPSC exercise its jurisdiction to investigate the operation of the municipal franchise fee collection requirements applicable to the Company's electric and gas service, to approve the Company's efforts to correct any past franchise fee billing errors, to adopt improvements in the system which will reduce such errors in the future, and to adopt any regulation that the SCPSC deems just and proper to regulate the franchise fee collection process.

The Company is also engaged in various other claims and litigation incidental to its business operations which management anticipates will be resolved without material loss to the Company.

F. Operating Lease Commitments

The Company is obligated under various operating leases with respect to office space, furniture and equipment. Leases expire at various dates through 2009. Rent expense totaled approximately $9.9 million, $9.9 million and $9.3 million in 2004, 2003 and 2002, respectively. Future minimum rental payments under such leases areas follows:

	Millions
2005	$11.5
2006	11.2
2007	9.5
2008	8.7
2009	7.4
	$48.3

At December 31, 2004 minimum rentals to be received under noncancelable subleases with remaining lease terms in excess of one year totaled approximately $8.6 million.

G. Purchase Commitments

The Company is obligated for purchase commitments that expire at various dates through 2034, Purchase commitments expensed for coal supply, nuclear fuel contracts, construction projects and other commitments totaled $348.3 million, $276.5 million and $279.0 million in 2004, 2003 and 2002, respectively. Amounts expensed under coal contracts are based on a weighted average cost which includes spot market purchases and freight expenditures. Coal spot market purchases represented

13%-14.5% of coal expense for the years 2002-2004. Future payments under such purchase commitments are as follows:

	Millions
2005	$372.2
2006	300.8
2007	114.8
2008	55.5
2009	0.4
Thereafter	12.3
	$856.0

In addition, included in purchase commitments are customary purchase orders under which the Company has the option to utilize certain vendors without the obligation to do so. The Company may terminate such commitments without penalty.

11. SEGMENT OF BUSINESS INFORMATION

The Company's reportable segments are Electric Operations and Gas Distribution. The accounting policies of the segments are the same as those described in the summary of significant accounting policies. The Company records intersegment sales and transfers of electricity and gas based on rates established by the appropriate regulatory authority. Non-regulated sales and transfers are recorded at current market prices.

Electric Operations is primarily engaged in the generation, transmission, and distribution of electricity, and is regulated by the SCPSC and by FERC. Gas Distribution is engaged in the purchase and sale, primarily at retail, of natural gas, and is regulated by the SCPSC.

The Company's reportable segments share a similar regulatory environment and, in some cases, overlapping service areas. However, Electric Operations' product differs from Gas Distribution, as does its generation process and method of distribution.

Disclosure of Reportable Segments (Millions)

2004	Electric Operations	Gas Distribution	All Other	Adjustments/ Eliminations	Consolidated Total
Customer Revenue	$1,692	$397	—	—	$2,089
Intersegment Revenue	—	1	—	$ (1)	—
Operating Income (Loss)	550	14	—	(89)	475
Interest Expense	10	—	—	129	139
Depreciation & Amortization	208	13	—	—	221
Segment Assets	5,365	354	—	1,261	6,980
Expenditures for Assets	389	35	—	20	444

2003	Electric Operations	Gas Distribution	All Other	Adjustments/ Eliminations	Consolidated Total
Customer Revenue	$1,472	$360	—	—	$1,832
Intersegment Revenue	—	1	—	$ (1)	—
Operating Income (Loss)	426	15	—	(1)	440
Interest Expense	7	—	$2	127	136
Depreciation & Amortization	183	13	—	—	196
Segment Assets	5,038	323	—	1,267	6,628
Expenditures for Assets	655	20	—	(25)	650

2002	Electric Operations	Gas Distribution	All Other	Adjustments/ Eliminations	Consolidated Total
Customer Revenue	$1,385	$298	—	—	$1,683
Intersegment Revenue	—	2	—	$ (2)	—
Operating Income (Loss)	418	15	—	(2)	431
Interest Expense	8	n/a	$4	111	123
Depreciation & Amortization	167	12	—	—	179
Segment Assets	4,511	315	—	1,166	5,992
Expenditures for Assets	625	19	—	(35)	609

Management uses operating income to measure segment profitability for regulated operations and evaluates utility plant, net, for its segments. As a result, the Company does not allocate interest charges, income tax expense or assets other than utility plant to its segments. Interest income is not reported by segment and is not material. In accordance with SFAS 109, the Company's deferred tax assets are netted with deferred tax liabilities for reporting purposes.

The Consolidated Financial Statements report operating revenues which are comprised of the reportable segments. Revenues from non-reportable segments are included in Other Income. Therefore, the adjustments to total revenue remove revenues from non-reportable segments. Segment assets include utility plant, net for all reportable segments. As a result, adjustments to assets include non-utility plant and non-fixed assets for the segments. Interest Expense is adjusted to include the totals from the Company that are not allocated to the segments and to eliminate inter-segment charges.

12. QUARTERLY FINANCIAL DATA (UNAUDITED)

2004 Millions	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Annual
Total operating revenues	$527	$503	$555	$504	$2,089
Operating income	113	114	162	86	475
Net income	54	57	85	36	232

2003 Millions	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Annual
Total operating revenues	$478	$422	$484	$448	$1,832
Operating income	102	91	154	93	440
Net income	47	40	88	45	220

PUBLIC SERVICE COMPANY
OF NORTH CAROLINA, INCORPORATED

Public Service Company of North Carolina, Incorporated meets the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and therefore is filing this form with the reduced disclosure format allowed under General Instruction I(2).

ITEM 7. MANAGEMENT'S NARRATIVE ANALYSIS OF RESULTS OF OPERATIONS

Statements included in this narrative analysis of Public Service Company of North Carolina, Incorporated's (and together with its consolidated subsidiaries, PSNC Energy) (or elsewhere in this annual report) which are not statements of historical fact are intended to be, and are hereby identified as, forward-looking statements for purposes of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Readers are cautioned that any such forward-looking statements are not guarantees of future performance and involve a number of risks and uncertainties, and that actual results could differ materially from those indicated by such forward-looking statements. Important factors that could cause actual results to differ materially from those indicated by such forward-looking statements include, but are not limited to, the following: (1) that the information is of a preliminary nature and may be subject to further and/or continuing review and adjustment, (2) regulatory actions or changes in the utility regulatory environment, (3) current and future litigation, (4) changes in the economy, especially in PSNC Energy's service territory, (5) the impact of competition from other energy suppliers, including competition from alternate fuels in industrial interruptible markets, (6) growth opportunities, (7) the results of financing efforts, (8) changes in PSNC Energy's accounting policies, (9) weather conditions, especially in areas served by PSNC Energy, (10) performance of SCANA Corporation's (SCANA) pension plan assets and the impact on PSNC Energy's results of operations, (11) inflation, (12) changes in environmental regulations, and (13) the other risks and uncertainties described from time to time in PSNC Energy's periodic reports filed with the SEC including those described in Item 1 under Risk Factors. PSNC Energy disclaims any obligation to update any forward-looking statements.

Net Income

Net income for the years ended December 31, 2004 and 2003 was as follows:

	2004	% Change	2003
	Millions of dollars		
Net income	$23.7	(23)%	$30.9

Net income decreased approximately $7.2 million, primarily due to decreased margin of $2.2 million, higher operating expenses of $3.5 million and lower other income of $1.2 million.

The nature of PSNC Energy's business is seasonal. The quarters ending March 31 and December 31 are generally PSNC Energy's most profitable quarters due to increased demand for natural gas related to space heating requirements.

PSNC Energy's Board of Directors authorized the following distributions/dividends on common stock held by SCANA during 2004:

Declaration Date	Distribution	Quarter Ended	Payment Date
February 19, 2004	$4.0 million	March 31, 2004	April 1, 2004
April 29, 2004	$3.5 million	June 30, 2004	July 1, 2004
July 29, 2004	$3.0 million	September 30, 2004	October 1, 2004
October 29, 2004	$3.5 million	December 31, 2004	January 1, 2005

Gas Distribution

Gas distribution sales margins for 2004 and 2003 were as follows:

	2004	2003	Change	% Change
		Millions of dollars		
Operating revenues	$ 516.5	$ 508.9	$ 7.6	1.5%
Less: Cost of gas	(341.6)	(330.4)	(11.2)	(3.4)%
Gross margin	$ 174.9	$ 178.5	$ (3.6)	(2.0)%

Gas distribution sales margin for the year ended December 31, 2004 decreased approximately $5.1 million due to lower natural gas usage attributable to milder weather and $2.9 million due to a negative impact from changes in the benchmark cost of gas. The margin decrease was partially offset by $4.0 million primarily due to customer growth of 3.7%.

Operation and Maintenance Expenses

The $5.3 million increase in operation and maintenance expenses in 2004 is primarily due to increased labor and benefits costs of $4.3 million and increased administrative and general business expenses of $2.6 million, partially offset by decreased bad debt expense of $1.4 million.

Other Income

Other income decreased for the year ended December 31, 2004 primarily due to a $1.0 million loss recognized on the sale of PSNC Energy's former corporate headquarters in Gastonia, North Carolina and decreased interest income of $0.6 million on amounts under-collected from customers through the operation of the Rider D mechanism.

Capital Expansion Program and Liquidity Matters

PSNC Energy's capital expansion program includes the construction of lines, systems and facilities and the purchase of related equipment. PSNC Energy's 2005 construction budget is approximately $58.0 million, compared to actual construction expenditures for 2004 of $50.3 million.

The U. S. Congress passed the Pipeline Safety Improvement Act of 2002 (the Pipeline Safety Act), directing the U. S. Department of Transportation to establish a pipeline integrity management rule for operations of natural gas systems with transmission pipelines located near moderate to high density populations. Of PSNC Energy's approximately 720 miles of transmission pipeline subject to the Pipeline Safety Act, approximately 110 miles are located within these areas. Fifty percent of these miles of pipeline must be assessed by December 2007, and the remainder by December 2012. Depending on the assessment method used, PSNC Energy will be required to reinspect these same miles of pipeline every five to seven years. Though cost estimates for this project were developed using various assumptions, each of which are subject to imprecision, PSNC Energy currently estimates the total cost to be $10 million for the initial assessments and any subsequent remediation required through December 2012.

PSNC Energy's contractual cash obligations as of December 31, 2004 are summarized as follows:

Contractual Cash Obligations

December 31, 2004 (Millions of dollars)	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
Long-term and short-term debt (including interest)	$ 561	$ 80	$ 65	$ 42	$374
Operating leases	1	1	—	—	—
Purchase obligations	39	3	31	5	—
Other commercial commitments	759	246	172	111	230
Total	$1,360	$330	$268	$158	$604

Included in other commercial commitments are estimated obligations under forward contracts for natural gas purchases, transportation and storage. Many of these forward contracts for natural gas purchases include customary "make-whole" or default provisions, but are not considered to be "take-or-pay" contracts. Because these contracts relate to regulated gas businesses, their effects on gas costs are reflected in gas rates.

Included in purchase obligations are customary purchase orders under which PSNC Energy has the option to utilize certain vendors without the obligation to do so. PSNC Energy may terminate such obligations without penalty.

Financing Limits and Related Matters

PSNC Energy's issuance of various securities, including long-term and short-term debt, is subject to customary approval or authorization by state and federal regulatory bodies including the NCUC and the SEC. The Indenture under which these securities are issued contains no specific limit on the amount which may be issued.

At December 31, 2004 PSNC Energy had available the following securities to meet its liquidity needs:

	Millions of dollars
Lines of credit:	
Committed (expires June 2009)	$ 125
Short-term borrowings outstanding:	
Commercial paper (270 or fewer days)	58
Weighted average interest rate	2.47%

PSNC Energy is party to one interest rate swap agreement which allows it to pay variable rates and receive fixed rates on a notional amount of $25.6 million at December 31, 2004. See Note 7 to the consolidated financial statements. PSNC Energy utilizes no off-balance sheet financings or similar arrangements other than incidental operating leases, generally for office space, office furniture and equipment.

Competition

Natural gas competes with electricity, propane and heating oil to serve the heating and, to a lesser extent, the other household energy needs of residential and small commercial customers. This competition is generally based on price and convenience. Large commercial and industrial customers often have the ability to switch from natural gas to an alternate fuel, such as propane or fuel oil. Natural gas competes with these alternate fuels based on price. As a result, any significant disparity between supply and demand, either of natural gas or of alternate fuels, and due either to production or delivery disruptions or other factors, will affect the price and impact PSNC Energy's ability to retain large commercial and industrial customers on a monthly basis.

The NCUC has approved a rate structure that allows PSNC Energy to negotiate reduced rates in order to match the cost of alternate fuels to large commercial and industrial customers and recover the lost margin from other classes of customers. PSNC Energy anticipates that the need to negotiate reduced rates with these customers will continue.

Critical Accounting Policies and Estimates

Following are descriptions of PSNC Energy's accounting policies which are most critical in terms of reporting financial conditions or results of operations.

SFAS 71—PSNC Energy is subject to the provisions of SFAS 71, *"Accounting for the Effects of Certain Types of Regulation,"* which requires it to record certain assets and liabilities that defer the recognition of expenses and revenues to future periods as a result of being rate-regulated. At December 31, 2004 PSNC Energy had recorded approximately \$26.8 million and \$94.2 million of regulatory assets (including environmental) and liabilities, respectively, including amounts recorded for deferred income tax assets and liabilities. The NCUC has reviewed and approved most of the items shown as regulatory assets through specific orders. Other items represent costs which were not yet approved for recovery. In recording these costs as regulatory assets, management believes the costs will be allowable under existing rate-making concepts that are embodied in current rate orders received by PSNC Energy. However, ultimate recovery is subject to NCUC approval. In the future, as a result of deregulation or other changes in the regulatory environment, PSNC Energy may no longer meet the criteria for continued application of SFAS 71 and could be required to write off its regulatory assets and liabilities. Such an event could have a material adverse effect on the results of operations of PSNC Energy's Gas Distribution segment in the period the write-off would be recorded. It is not expected that cash flows or financial position would be materially affected.

Certain of PSNC Energy's regulatory assets and other deferred liabilities arise from its environmental assessment program, which identifies and evaluates current and former operations sites that could require environmental cleanup. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and clean up each site. These estimates are refined as additional information becomes available; therefore, actual expenditures could differ significantly from the original estimates. Regulatory assets and other deferred liabilities related to environmental cleanup affect primarily the Gas Distribution segment and are due to the costs associated with current and former MGP sites.

Revenue Recognition / Unbilled Revenues—Revenues related to the sale of energy are recorded when service is rendered or when energy is delivered to customers. Because customers are billed on cycles which vary based on the timing of the actual reading of their gas meters, PSNC Energy records estimates for unbilled revenues at the end of each reporting period. Such unbilled revenue amounts reflect estimates of the amount of gas delivered to each customer since the date of the last reading of their respective meters. Such unbilled revenues reflect consideration of estimated usage by customer class, the effects of different rate schedules, changes in weather and, where applicable, the impact of weather normalization provisions of rate structures. The accrual of unbilled revenues in this manner properly matches revenues and related costs. As of December 31, 2004 and 2003, accounts receivable included unbilled revenues of \$50.0 million and \$38.3 million, respectively, compared to total revenues for 2004 and 2003 of \$516.5 million and \$508.9 million, respectively.

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

All financial instruments held by PSNC Energy described below are held for purposes other than trading.

Interest rate risk—The tables below provide information about long-term debt issued by PSNC Energy and other financial instruments that are sensitive to changes in interest rates. For debt obligations, the tables present principal cash flows and related weighted average interest rates by expected maturity dates. For interest rate swaps, the figures shown reflect notional amounts and related maturities. Fair values for debt and swaps represent quoted market prices.

December 31, 2004 Millions of dollars	Expected Maturity Date 2005	2006	2007	2008	2009	Thereafter	Total	Fair Value
Liabilities								
Long-Term Debt:								
Fixed Rate ($)	3.2	3.2	3.2	3.2	3.2	259.6	275.6	325.8
Average Fixed Interest Rate (%)	8.75	8.75	8.75	8.75	8.75	6.9	7.0	
Interest Rate Swaps:								
Pay Variable/Receive Fixed ($)	3.2	3.2	3.2	3.2	3.2	9.6	25.6	1.2
Average Pay Interest Rate (%)	5.74	5.74	5.74	5.74	5.74	5.74	5.74	
Average Receive Interest Rate (%)	8.75	8.75	8.75	8.75	8.75	8.75	8.75	

December 31, 2003 Millions of dollars	Expected Maturity Date 2004	2005	2006	2007	2008	Thereafter	Total	Fair Value
Liabilities								
Long-Term Debt:								
Fixed Rate ($)	7.5	3.2	3.2	3.2	3.2	262.8	283.1	321.1
Average Fixed Interest Rate (%)	9.47	8.75	8.75	8.75	8.75	7.0	7.1	
Interest Rate Swaps:								
Pay Variable/Receive Fixed ($)	7.5	3.2	3.2	3.2	3.2	12.8	33.1	1.9
Average Pay Interest Rate (%)	4.7	4.36	4.36	4.36	4.36	4.36	4.7	
Average Receive Interest Rate (%)	8.9	8.75	8.75	8.75	8.75	8.75	8.9	

While a decrease in interest rates would increase the fair value of debt, it is unlikely that events which would result in a realized loss will occur.

PSNC Energy hedges gas purchasing activities using NYMEX futures and options. PSNC Energy's tariffs include a provision for the recovery of actual gas costs incurred. PSNC Energy records transaction fees and any realized gains or losses from derivatives acquired as part of its hedging program in deferred accounts as regulatory assets and liabilities for the over or under recovery of gas costs. In a November 2004 order, in connection with PSNC Energy's 2004 annual prudency review, the NCUC determined that PSNC Energy's gas costs, including all hedging transactions, were reasonably and prudently incurred during the 12-month review period ended March 31, 2004.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Public Service Company of North Carolina, Incorporated:

We have audited the accompanying Consolidated Balance Sheets of Public Service Company of North Carolina, Incorporated and subsidiaries (the "Company") as of December 31, 2004 and 2003, and the related Consolidated Statements of Operations, Changes in Common Equity and Comprehensive Income (Loss) and of Cash Flows for each of the three years in the period ended December 31, 2004. Our audits also included the financial statement schedule listed in Part IV at Item 15. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Public Service Company of North Carolina, Incorporated and subsidiaries at December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

As discussed in Note 1 to the consolidated financial statements, the Company adopted Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangibles," effective January 1, 2002.

/s/ Deloitte & Touche LLP
Columbia, South Carolina
February 28, 2005

PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INCORPORATED

CONSOLIDATED BALANCE SHEETS

December 31, (Millions of dollars)	2004	2003
Assets		
Gas Utility Plant	$ 947	$ 923
Accumulated depreciation	(262)	(256)
Acquisition adjustment	210	210
Gas Utility Plant, Net	895	877
Nonutility Property and Investments, Net	27	28
Current Assets:		
Cash and cash equivalents	1	18
Restricted cash and temporary investments	8	7
Receivables, net of allowance for uncollectible accounts of $2 and $2	128	115
Receivables—affiliated companies	7	5
Inventories (at average cost):		
Stored gas	70	56
Materials and supplies	5	5
Prepayments	2	2
Deferred income taxes, net	4	3
Other	1	—
Total Current Assets	226	211
Deferred Debits:		
Due from affiliate-pension asset	12	13
Regulatory assets	27	17
Other	4	6
Total Deferred Debits	43	36
Total	$1,191	$1,152

December 31, (Millions of dollars)	2004	2003
Capitalization and Liabilities		
Capitalization:		
Common equity	$ 513	$ 502
Long-term debt, net	274	278
Total Capitalization	787	780
Current Liabilities:		
Short-term borrowings	58	55
Current portion of long-term debt	3	8
Accounts payable	66	48
Accounts payable—affiliated companies	8	2
Customer deposits	8	7
Taxes accrued	4	10
Interest accrued	6	6
Distributions/dividends declared	4	4
Other	17	15
Total Current Liabilities	174	155
Deferred Credits:		
Deferred income taxes, net	105	96
Deferred investment tax credits	1	2
Due to affiliate-postretirement benefits	19	17
Other regulatory liabilities	10	9
Asset retirement obligations	84	77
Other	11	16
Total Deferred Credits	230	217
Commitments and Contingencies (Note 8)	—	—
Total	$1,191	$1,152

See Notes to Consolidated Financial Statements.

PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INCORPORATED
CONSOLIDATED STATEMENTS OF OPERATIONS

For the Years Ended December 31, (Millions of dollars)	2004	2003	2002
Operating Revenues	$516	$509	$ 356
Cost of Gas	341	330	190
Gross Margin	175	179	166
Operating Expenses:			
Operation and maintenance	80	75	70
Depreciation and amortization	34	34	35
Other taxes	8	7	7
Total Operating Expenses	122	116	112
Operating Income	53	63	54
Other Income (Loss), Including Allowance for Equity Funds Used During Construction	2	4	(1)
Interest Charges, Net of Allowance for Borrowed Funds Used During Construction	21	21	21
Income Before Income Taxes, Earnings from Equity Method Investees and Cumulative Effect of Accounting Change	34	46	32
Income Taxes	13	18	12
Income Before Earnings from Equity Method Investees and Cumulative Effect of Accounting Change	21	28	20
Earnings from Equity Method Investees, net of taxes	3	3	3
Income Before Cumulative Effect of Accounting Change	24	31	23
Cumulative Effect of Accounting Change, net of taxes	—	—	(230)
Net Income (Loss)	$ 24	$ 31	$(207)

See Notes to Consolidated Financial Statements.

PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INCORPORATED
CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31, (Millions of dollars)	2004	2003	2002
Cash Flows From Operating Activities:			
Net income (loss)	$ 24	$ 31	$(207)
Adjustments to reconcile net income to net cash provided from operating activities:			
Cumulative effect of accounting change, net of taxes	—	—	230
Depreciation and amortization	37	36	37
Loss on sale of assets	1	—	—
Allowance for funds used during construction	(1)	(1)	(1)
Change in certain assets and liabilities:			
(Increase) decrease in receivables, net	(15)	(18)	(31)
(Increase) decrease in inventories	(14)	(17)	11
(Increase) decrease in regulatory assets	1	—	1
Increase (decrease) in regulatory liabilities	1	—	1
Increase (decrease) in accounts payable	24	(1)	1
Increase (decrease) in deferred income taxes, net	8	5	2
Increase (decrease) in taxes accrued	(6)	5	—
Changes in gas adjustment clause, net	(11)	11	(24)
Changes in other assets	—	—	(6)
Changes in other liabilities	2	4	4
Net Cash Provided From Operating Activities	51	55	18
Cash Flows From Investing Activities:			
Construction expenditures, net of AFC	(49)	(47)	(47)
Proceeds on sale of assets	—	12	—
Nonutility and other	(1)	(1)	(1)
Net Cash Used In Investing Activities	(50)	(36)	(48)
Cash Flows From Financing Activities:			
Short-term borrowings, net	3	24	31
Capital contributions from parent, net	1	1	—
Retirement of long-term debt	(8)	(8)	(4)
Distributions/dividend payments	(14)	(19)	(14)
Net Cash Provided From (Used In) Financing Activities	(18)	(2)	13
Net Increase (Decrease) in Cash and Cash Equivalents	(17)	17	(17)
Cash and Cash Equivalents, January 1	18	1	18
Cash and Cash Equivalents, December 31	$ 1	$ 18	$ 1
Supplemental Cash Flow Information:			
Cash paid for: Interest (net of capitalized interest of $1, $1 and $1)	$ 19	$ 19	$ 19
Income taxes	11	8	14

The implementation of SFAS 142 resulted in a $230 million non-cash write-down of the acquisition adjustment in 2002. See Note 1G.

See Notes to Consolidated Financial Statements.

PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INCORPORATED

CONSOLIDATED STATEMENTS OF CHANGES IN COMMON EQUITY AND COMPREHENSIVE INCOME (LOSS)

	Common Stock		Capital in Excess of Par	Accumulated Other Comprehensive Loss	Retained Earnings (Deficit)	Total Common Equity
	Shares	Amount				
			Millions of dollars			
Balance at December 31, 2001	1,000	—	$706	—	$ 9	$ 715
Net Loss					(207)	(207)
Unrealized Losses on Hedging Activities, net of taxes ($0.5)				$(1)		(1)
Comprehensive Loss				(1)	(207)	(208)
Cash Distributions/Dividends Declared			(20)			(20)
Balance at December 31, 2002	1,000	—	686	(1)	(198)	487
Capital Contributions from Parent, net			1			1
Net Income/Comprehensive Income					31	31
Cash Distributions/Dividends Declared			(17)			(17)
Balance at December 31, 2003	1,000	—	670	(1)	(167)	502
Capital Contributions from Parent, net			1			1
Net Income/Comprehensive Income					24	24
Cash Distributions/Dividends Declared			(14)			(14)
Balance at December 31, 2004	1,000	—	$657	$(1)	$(143)	$ 513

See Notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A. Organization and Principles of Consolidation

Public Service Company of North Carolina, Incorporated (PSNC Energy, and together with its consolidated subsidiaries, the Company), a public utility, was organized as a North Carolina corporation in 1938. Effective January 1, 2000 the acquisition of the Company by SCANA Corporation (SCANA), a South Carolina holding company, was consummated in a business combination accounted for as a purchase. As a result, the Company became a wholly owned subsidiary of SCANA, incorporated under the laws of South Carolina. The Company is engaged predominantly in the purchase, sale, transportation and distribution of natural gas to residential, commercial and industrial customers in North Carolina.

The accompanying Consolidated Financial Statements include the accounts of PSNC Energy and its subsidiary companies, Clean Energy Enterprises, Inc., PSNC Blue Ridge Corporation, and PSNC Cardinal Pipeline Company. Investments in other affiliates in which the Company has the ability to exercise influence over operating and financial policies are accounted for under the equity method. Significant intercompany balances and transactions have been eliminated in consolidation.

B. Basis of Accounting

The Company accounts for its regulated utility operations, assets and liabilities in accordance with the provisions of Statement of Financial Accounting Standards (SFAS) 71, *"Accounting for the Effects of Certain Types of Regulation."* SFAS 71 requires cost-based rate-regulated utilities to recognize in their financial statements certain revenues and expenses in different time periods than do enterprises that are not rate-regulated. As a result, the Company has recorded, as of December 31, 2004, approximately $27 million and $94 million of regulatory assets (including environmental) and liabilities, respectively, as shown below.

	December 31, 2004	December 31, 2003
	Millions of dollars	
Excess deferred income taxes	$ (1)	—
Under- (over-) collections—gas cost adjustment clause, net	10	$ (1)
Deferred environmental remediation costs	8	9
Asset retirement obligations	(84)	(77)
Total	$(67)	$(69)

Excess deferred income taxes represent deferred income taxes recorded in prior years at a rate higher than the current statutory rate. Pursuant to a North Carolina Utilities Commission (NCUC) order, the Company was required to refund these amounts to customers through a rate decrement.

Under-(over-) collections—gas cost adjustment clause, net represents amounts under- or over-collected from customers pursuant to the Company's Rider D mechanism approved by the NCUC. This mechanism allows the Company to recover all prudently incurred gas costs. See Note 1F.

Deferred environmental remediation costs represents costs associated with the assessment and cleanup of manufactured gas plant (MGP) sites currently or formerly owned by the Company. A portion of the costs incurred has been recovered through rates. Amounts incurred and deferred, net of insurance settlements, that are not currently being recovered through rates are approximately $1.4 million. See Note 8. Management believes these costs and the remaining costs of approximately $6.5 million will be recoverable.

Asset retirement obligations represent net collections through depreciation rates of estimated costs to be incurred for the future retirement of assets for which no legal retirement obligation exists.

The NCUC has reviewed and approved through specific orders most of the items shown as regulatory assets. Other items represent costs which are not yet approved for recovery by the NCUC. In recording these costs as regulatory assets, management believes the costs will be allowable under existing rate-making concepts that are embodied in current rate orders received by the Company. However, ultimate recovery is subject to NCUC approval. In the future, as a result of deregulation or other changes in the regulatory environment, the Company may no longer meet the criteria for continued application of SFAS 71 and could be required to write off its regulatory assets and liabilities. Such an event could have a material adverse effect on the Company's results of operations, liquidity or financial position in the period the write-off would be recorded.

C. System of Accounts

The accounting records of the Company are maintained in accordance with the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission (FERC) and as adopted by the NCUC.

D. Utility Plant

Utility plant is stated substantially at original cost. The costs of additions, renewals and betterments to utility plant, including direct labor, material and indirect charges for engineering, supervision and an allowance for funds used during construction, are added to utility plant accounts. The original cost of utility property retired or otherwise disposed of is removed from utility plant accounts and generally charged to accumulated depreciation. The costs of repairs, replacements and renewals of items of property determined to be less than a unit of property or that do not increase the asset's life or functionality are charged to maintenance expense.

E. Allowance for Funds Used During Construction (AFC)

AFC, a noncash item, reflects the period cost of capital devoted to plant under construction. This accounting practice results in the inclusion of, as a component of construction cost, the costs of debt and equity capital dedicated to construction investment. AFC is included in rate base investment and depreciated as a component of plant cost in establishing rates for utility services. The Company has calculated AFC using composite rates of 8.0%, 12.7% and 12.1% for the years ended December 31, 2004, 2003 and 2002, respectively. These rates do not exceed the maximum allowable rate as calculated under FERC Order No. 561.

F. Revenue Recognition

Revenues are recorded during the accounting period in which services are provided to customers, and include estimated amounts for natural gas delivered and facilities charges not yet billed. Unbilled revenues totaled approximately $50.0 million and $38.3 million as of December 31, 2004 and 2003, respectively.

The Company's Rider D mechanism authorizes the recovery of all prudently incurred gas costs from customers on a monthly basis. Any difference in amounts paid and collected for these costs is deferred for subsequent refund to or collection from customers, with interest. Additionally, the Company can recover its margin losses on negotiated gas sales to certain large commercial/industrial customers in a manner authorized by the NCUC. Pursuant to the operation of Rider D, at December 31, 2004 the Company had undercollected from customers approximately $10 million, net. The Company had overcollected from customers approximately $1.0 million, net, at December 31, 2003.

The Company's gas rate schedules for residential, small commercial and small industrial customers include a weather normalization adjustment, which minimizes fluctuations in gas revenues due to abnormal weather conditions. The Company establishes its commodity cost of gas for large commercial and industrial customers on the basis of market prices for natural gas as approved by the NCUC.

G. Depreciation and Amortization

Provisions for depreciation and amortization are recorded using the straight-line method and are based on the estimated service lives of the various classes of property. The composite weighted average depreciation rates for utility plant assets were 3.9%, 4.1% and 4.3% for 2004, 2003 and 2002, respectively.

The Company adopted SFAS 142, *"Goodwill and Other Intangible Assets,"* effective January 1, 2002. The Company considers the amounts categorized by FERC as "acquisition adjustments" to be goodwill as defined in SFAS 142 and ceased amortization of such amounts upon the adoption of SFAS 142. The Company has no other intangible assets. In connection with implementation of SFAS 142, the Company performed a valuation analysis of its acquisition adjustment using an independent appraisal. The analysis indicated that the carrying amount of the acquisition adjustment exceeded its fair value by approximately $230 million. The resulting impairment charge is reflected on the statement of operations as the cumulative effect of an accounting change. SFAS 142 requires that an impairment evaluation be performed annually and at the same time each year. Subsequent annual calculations required by SFAS 142 have indicated no need for further write-downs. Should a further write-down be required in the future, such a charge would be treated as an operating expense.

H. Income Taxes

The Company is included in the consolidated federal income tax return of SCANA. Under a joint consolidated income tax allocation agreement, each subsidiary's current and deferred tax expense is computed on a stand-alone basis. Deferred tax assets and liabilities are recorded for the tax effects of all significant temporary differences between the book basis and tax basis of assets and liabilities at currently enacted rates. Deferred tax assets and liabilities are adjusted for changes in such rates through charges or credits to regulatory assets or liabilities if they are expected to be recovered from, or passed through to, customers; otherwise they are charged or credited to income tax expense. Also, under provisions of the income tax allocation agreement, certain tax benefits of the parent holding company are distributed in cash to tax paying affiliates, including the Company, in the form of capital contributions. In 2004 and 2003 net capital contributions of $1.0 million and $1.2 million, respectively, were received by the Company under such provisions.

I. Debt Premium, Discount and Expense, Unamortized Loss on Reacquired Debt

Long-term debt premium and discount are recorded in long-term debt and are amortized as components of interest on long-term debt over the terms of the respective debt issues. Other issuance expense and gains or losses on reacquired debt that is refinanced are recorded in other deferred debits or credits and amortized over the term of the replacement debt.

J. Environmental

The Company maintains an environmental assessment program to identify and evaluate current and former operation sites that could require environmental cleanup. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and clean up each site. These estimates are refined as additional information becomes available; therefore, actual expenditures could differ significantly from the original estimates. Amounts estimated and accrued to date for site assessments and cleanup relate solely to regulated operations. Such amounts are recorded in deferred debits and amortized with recovery provided through rates.

K. Cash and Cash Equivalents

The Company considers temporary cash investments having original maturities of three months or less to be cash equivalents. These cash equivalents are generally in the form of commercial paper, certificates of deposit, repurchase agreements, treasury bills and notes.

The Company receives refunds from its pipeline suppliers. Pursuant to an order of the NCUC, these funds must be segregated from the Company's general funds and can be used for expansion projects or refunded to customers. The Company reports these amounts in restricted cash. On February 24, 2005 the NCUC authorized the Company to refund restricted cash to customers by a direct bill credit in March 2005.

L. New Accounting Standards

SFAS 153, *"Exchanges of Nonmonetary Assets,"* was issued in December 2004 and amends APB 29, *"Accounting for Nonmonetary Transactions."* SFAS 153 makes a general exception from fair value measurement for exchanges of nonmonetary assets that do not have commercial substance. A nonmonetary exchange has commercial substance if the future cash flows of the entity are expected to change significantly as a result of the exchange. SFAS 153 applies prospectively to nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. The Company does not expect that the initial adoption of SFAS 153 will have a material impact on the Company's results of operations, cash flows or financial position.

M. Related Party Transactions

The Company has related party transactions with its equity method method investees. The Company records as cost of gas the storage and transportation costs charged by these investees. These costs totaled approximately $15.7 million, $16.5 million and $17.0 million in 2004, 2003 and 2002, respectively. The Company owed these investees approximately $1.3 million, $1.3 million and $1.4 million at December 31, 2004, 2003 and 2002, respectively. The Company recorded from equity investees approximately $4.7 million, $4.9 million and $5.1 million in cash distributions during 2004, 2003 and 2002, respectively.

Summarized aggregate unaudited financial information provided by the respective equity method investees as of and for the years ended December 31, 2004, 2003 and 2002, is presented below:

	2004	2003	2002
	Millions of dollars		
Current assets	$ 17	$ 22	$ 22
Non-current assets	185	190	194
Current liabilities	11	14	13
Non-current liabilities	83	89	97
Revenues	35	36	37
Gross profit	35	36	37
Income before income taxes	18	18	19

At December 31, 2004 an affiliate owed the Company $2.7 million for natural gas and transportation services. Additionally, the Company owed an affiliate $0.2 million related to billing and collection services for the sale of energy-related products and service contracts.

Effective January 1, 2001 PSNC Production Corporation (PSNC Production) and SCANA Public Service Company LLC were sold to SCANA Energy Marketing, Inc. (SEMI), a subsidiary of SCANA, for $4.4 million, which approximated their net book value. During the fourth quarter 2003, SEMI paid the Company $9.4 million for an outstanding receivable due from PSNC Production. The receivable was for cash advanced by the Company to PSNC Production prior to the sale.

N. Reclassifications

Certain amounts from prior periods have been reclassified to conform with the presentation adopted for 2004.

O. Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

2. RATE AND OTHER REGULATORY MATTERS

The Company's rates are established using a benchmark cost of gas approved by the NCUC, which may be modified periodically to reflect changes in the market price of natural gas. The Company revises its tariffs with the NCUC as necessary to track these changes and accounts for any over- or under-collections of the delivered cost of gas in its deferred accounts for subsequent rate consideration. The NCUC reviews the Company's gas purchasing practices annually.

The Company's benchmark cost of gas in effect during 2004 and 2003 was as follows:

Rate Per Therm	Effective Date
$.460	January-February 2003
$.595	March 2003
$.725	April-November 2003
$.600	December 2003-September 2004
$.675	October-November 2004
$.825	December 2004

On February 24, 2005 the NCUC authorized the Company to refund approximately $7.8 million in pipeline supplier refunds by a direct bill credit to various customers in March 2005.

On February 3, 2005 the NCUC approved the Company's request to decrease the benchmark cost of gas from $.825 per therm to $.725 per therm for service rendered on and after February 1, 2005.

On January 21, 2005 the NCUC authorized the Company to defer for subsequent rate consideration certain expenses incurred to comply with the U. S. Department of Transportation's Pipeline Integrity Management requirements. This accounting treatment is effective November 1, 2004.

In September 2004, in connection with the Company's 2004 Annual Prudence Review, the NCUC determined that the Company's gas costs, including all hedging transactions, were reasonable and prudently incurred during the 12-month review period ended March 31, 2004. The NCUC also authorized new rate decrements to refund over-collections of certain gas costs included in the Company's deferred accounts, effective March 1, 2004.

A state expansion fund, established by the North Carolina General Assembly and funded by refunds from the Company's interstate pipeline transporters, provides financing for expansion into areas that otherwise would not be economically feasible to serve. In June 2000 the NCUC approved the Company's requests for disbursement of up to $28.4 million from the Company's expansion fund to extend natural gas service to Madison, Jackson and Swain Counties in western North Carolina. The final phase of this project was completed and placed in service in April 2004 at a total cost of approximately $30.3 million.

In December 1999 the NCUC issued an order approving SCANA's acquisition of the Company. As specified in the order, the Company agreed to a moratorium on general rate increases until after August 2005. General rate relief can be obtained during this period to recover costs associated with materially adverse governmental actions and force majeure events.

3. EMPLOYEE BENEFIT PLANS

The Company participates in SCANA's noncontributory defined benefit pension plan, which covers substantially all permanent employees. SCANA's pension plan benefits for employees of the Company are calculated using a cash balance formula under which employees earn benefits through monthly compensation and interest credits. SCANA's policy has been to fund the plan to the extent permitted by applicable federal income tax regulations as determined by an independent actuary. The Company also participates in SCANA's plan to provide certain unfunded health care and life insurance benefits to active and retired employees. Retirees share in a portion of their medical care cost and are provided life insurance benefits at no charge. The cost of postretirement benefits other than pensions are accrued during the years the employees render the service necessary to be eligible for the applicable benefits.

For the years ended December 31, 2004 and 2003, the Company's net periodic benefit cost was approximately $1.4 million and $1.2 million, respectively, for the pension plan, and net periodic benefit cost was approximately $3.3 million and $3.0 million, respectively, for the postretirement plan.

4. LONG-TERM DEBT

Long-term debt by type and related weighted average interest rates and maturities is as follows:

	Weighted-Average Rate	Year Due	December 31, 2004	December 31, 2003
		Millions of dollars		
Medium-Term Notes (unsecured)	6.63%	2011	$150	$150
Senior Debentures(a)	7.53%	2004-2026	126	134
Fair value of interest rate swaps			1	2
Total debt			277	286
Current maturities of long-term debt			(3)	(8)
Total long-term debt			$274	$278

(a) Includes $25.6 million and $33.1 million of fixed rate debt hedged by variable interest rate swaps for 2004 and 2003, respectively.

Annual amounts of long-term debt maturities are $3.2 million for each of the years 2005 through 2009.

5. LINES OF CREDIT AND SHORT-TERM BORROWINGS

	2004	2003
	Millions of dollars	
Lines of credit (total and unused)	$125.0	$125.0
Short-term borrowings outstanding:		
Commercial paper (270 or fewer days)	$ 57.8	$ 55.2
Weighted average interest rate	2.47%	1.17%

The Company pays fees to banks as compensation for maintaining committed lines of credit.

6. INCOME TAXES

Total income tax expense attributable to income (before cumulative effects of accounting changes) for 2004, 2003 and 2002 is as follows:

	2004	2003	2002
	Millions of dollars		
Current taxes:			
Federal	$ 3.2	$12.1	$ 9.7
State	2.5	3.3	2.0
Total current taxes	5.7	15.4	11.7
Deferred taxes, net:			
Federal	9.1	4.0	1.7
State	0.1	—	0.3
Total deferred taxes	9.2	4.0	2.0
Investment tax credits:			
Amortization of amounts deferred—Federal	(0.3)	(0.3)	(0.3)
Total investment tax credits	(0.3)	(0.3)	(0.3)
Total income tax expense	$14.6	$19.1	$13.4

The difference between actual income tax expense and that amount calculated from the application of the statutory 35% federal income tax rate to pre-tax income (before cumulative effect of accounting change) is reconciled as follows:

	2004	2003	2002
	Millions of dollars		
Income before cumulative effect of accounting change	$23.7	$30.9	$22.6
Income tax expense	14.6	19.1	13.4
Total pre-tax income	$38.3	$50.0	$36.0
Income taxes on above at statutory federal income tax rate	$13.4	$17.5	$12.6
Increases (decreases) attributed to:			
State income taxes (less federal income tax effect)	1.7	2.2	1.6
Amortization of federal investment tax credits	(0.3)	(0.3)	(0.3)
Other differences, net	(0.2)	(0.3)	(0.5)
Total income tax expense	$14.6	$19.1	$13.4

The tax effects of significant temporary differences comprising the Company's net deferred tax liability of $100.7 million at December 31, 2004 and $92.9 million at December 31, 2003 (see Note 1H) are as follows:

	2004	2003
	Million of dollars	
Deferred tax assets:		
Nondeductible reserves	$ 2.4	$ 1.0
Other	3.2	4.4
Total deferred tax assets	5.6	5.4
Deferred tax liabilities:		
Property, plant and equipment	94.5	92.3
Other	11.8	6.0
Total deferred tax liabilities	106.3	98.3
Net deferred tax liability	$100.7	$92.9

7. FINANCIAL INSTRUMENTS

The carrying amounts and estimated fair values of the Company's financial instruments at December 31, 2004 and 2003 are as follows:

	2004		2003	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	Millions of dollars			
Assets:				
Cash and cash equivalents	$ 1	$ 1	$ 18	$ 18
Liabilities:				
Short-term borrowings	57.8	57.8	55.2	55.2
Long-term debt	276.8	327.0	285.0	323.0

The following methods and assumptions were used to estimate the fair value of the above classes of financial instruments:

- Cash and cash equivalents are valued at their carrying amount.
- Fair values of long-term debt are based on quoted market prices of the instruments or similar instruments. The carrying values reflect the fair values of derivatives designated as hedges under SFAS 133 criteria (interest rate swaps) based on settlement values obtained from counterparties. Early settlement of long-term debt may not be possible or may not be considered prudent.
- Short-term borrowings are valued at their carrying amount.

In January 2003 the Company filed a summary of its hedging program for natural gas purchases with the NCUC for informational purposes. The primary goal of the program is to reduce price volatility to firm customers. In an October 2003 order, the NCUC declared the program was reasonable. Transaction fees and any gains or losses are recorded in deferred accounts for subsequent rate consideration. As of December 31, 2004 the Company had deferred net costs of approximately $1.8 million.

The Company uses interest rate swap agreements to manage interest rate risk. These swap agreements provide for the Company to pay variable and receive fixed interest payments and are designated as fair value hedges of certain debt instruments. The fair value of interest rate swaps is recorded within other deferred debits on the balance sheet. The resulting credits serve to reflect the hedged long-term debt at its fair value. Periodic receipts or payments related to the interest rate swaps are credited or charged to interest expense as incurred.

At December 31, 2004 the estimated fair value of the Company's swap was $1.2 million related to a notional amount of $25.6 million.

8. COMMITMENTS AND CONTINGENCIES

A. Environmental

The Company is responsible for environmental cleanup at five sites in North Carolina on which manufactured gas plant (MGP) residuals are present or suspected. The Company's actual remediation costs for these sites will depend on a number of factors, such as actual site conditions, third-party claims and recoveries from other potentially responsible parties. The Company has recorded a liability and associated regulatory asset of approximately $6.5 million, which reflects its estimated remaining liability at December 31, 2004. Amounts incurred and deferred to date, net of insurance settlements, that are not currently being recovered through gas rates are approximately $1.4 million. Management believes that all MGP cleanup costs will be recoverable through gas rates.

B. Claims and Litigation

The Company is engaged in various claims and litigation incidental to its business operations which management anticipates will be resolved without material loss to the Company.

C. Purchase Commitments

The Company is obligated for purchase commitments that expire at various dates through 2019. Purchase commitments expensed for gas supply, transportation, storage and other commitments totaled $402.0 million, $288.4 million and $153.6 million in 2004, 2003 and 2002, respectively. Future payments under such purchase commitments are as follows:

	Millions
2005	$248.5
2006	89.6
2007	58.0
2008	55.9
2009	60.3
Thereafter	285.8
	$798.1

Included in purchase obligations are customary purchase orders under which the Company has the options to utilize certain vendors without the obligation to do so. The Company may terminate such purchase obligations without penalty.

9. SEGMENT OF BUSINESS INFORMATION

Gas Distribution is comprised of the Company's local distribution operations, and operating income is used to measure its profitability. The All Other segment is comprised solely of the Company's two equity method investees. One investee owns a 105-mile gas transmission pipeline, and the other owns a liquefaction, storage and regasification facility. Both investees are located in North

Carolina. Net income is used to measure profitability for the All Other segment. The Company did not have intersegment revenue for any period reported.

Disclosure of Reportable Segments (Millions)

2004	Gas Distribution	All Other	Adjustments/ Eliminations	Consolidated Total
External Revenue	$ 516	—	—	$ 516
Depreciation & Amortization	34	—	—	34
Operating Income	53	n/a	—	53
Net Income	n/a	$ 3	$ 21	24
Interest Expense	21	—	—	21
Segment Assets	1,094	28	69	1,191
Expenditures for Assets	50	—	—	50
Deferred Tax Assets	4	—	—	4

2003	Gas Distribution	All Other	Adjustments/ Eliminations	Consolidated Total
External Revenue	$ 509	—	—	$ 509
Depreciation & Amortization	34	—	—	34
Operating Income	63	n/a	—	63
Net Income	n/a	$ 3	$ 28	31
Interest Expense	21	—	—	21
Segment Assets	1,067	28	57	1,152
Expenditures for Assets	48	—	—	48
Deferred Tax Assets	3	—	—	3

2002	Gas Distribution	All Other	Adjustments/ Eliminations	Consolidated Total
External Revenue	$ 356	—	—	$ 356
Depreciation & Amortization	35	—	—	35
Operating Income	54	n/a	—	54
Net Income	n/a	$ 3	$(210)	(207)
Interest Expense	21	—	—	21
Segment Assets	1,010	28	55	1,093
Expenditures for Assets	48	—	—	48
Deferred Tax Assets	3	—	—	3

10. QUARTERLY FINANCIAL DATA (UNAUDITED)

2004 Millions	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Annual
Total operating revenues	$226	$69	$53	$168	$516
Operating income (loss)	42	(3)	(6)	20	53
Net income (loss)	23	(4)	(6)	11	24

2003 Millions	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Annual
Total operating revenues	$203	$82	$59	$165	$509
Operating income (loss)	42	—	(8)	29	63
Net income (loss)	24	(2)	(7)	16	31

PART II, ITEM 9A, PART III AND PART IV

SCANA CORPORATION
SOUTH CAROLINA ELECTRIC & GAS COMPANY
PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INCORPORATED

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

Not Applicable.

ITEM 9A. CONTROLS AND PROCEDURES

SCANA:

Evaluation of Disclosure Controls and Procedures:

As of December 31, 2004, an evaluation was performed under the supervision and with the participation of SCANA's management, including the CEO and CFO, of the effectiveness of the design and operation of the Company's disclosure controls and procedures. Based on that evaluation, SCANA's management, including the CEO and CFO, concluded that SCANA's disclosure controls and procedures were effective as of December 31, 2004. There has been no change in SCANA's internal controls over financial reporting during the quarter ended December 31, 2004 that has materially affected or is reasonably likely to materially affect SCANA's internal control over financial reporting.

Management's Evaluation of Internal Control Over Financial Reporting:

Pursuant to Section 404 of the Sarbanes-Oxley Act of 2002, management is required to include in this Form 10-K an internal control report wherein management states its responsibility for establishing and maintaining adequate internal control structure and procedures for financial reporting and assesses the effectiveness of such structure and procedures. This management report follows.

MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of SCANA Corporation (SCANA) is responsible for establishing and maintaining adequate internal control over financial reporting. SCANA's internal control system was designed to provide reasonable assurance to SCANA's management and board of directors regarding the preparation and fair presentation of published financial statements.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, the effectiveness of the internal control over financial reporting may deteriorate in future periods due to either changes in conditions or declining levels of compliance with policies or procedures.

SCANA's management assessed the effectiveness for SCANA's internal control over financial reporting as of December 31, 2004. In making this assessment, SCANA used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control—Integrated Framework. Based on this assessment, SCANA's management believes that, as of December 31, 2004, internal control over financial reporting is effective based on those criteria.

SCANA's independent registered public accounting firm has issued an attestation report on the assessment of SCANA's internal control over financial reporting. This report follows.

February 28, 2005

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

SCANA Corporation

We have audited management's assessment, included in the accompanying Management Report On Internal Control Over Financial Reporting, that SCANA Corporation and subsidiaries (the "Company") maintained effective internal control over financial reporting as of December 31, 2004, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that SCANA Corporation and subsidiaries maintained effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, SCANA Corporation and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2004, of SCANA Corporation and subsidiaries and our report dated February 28, 2005, expressed an unqualified opinion on those financial statements and financial statement schedule.

DELOITTE & TOUCHE LLP
Columbia, South Carolina
February 28, 2005

SCE&G:

Evaluation of Disclosure Controls and Procedures:

As of December 31, 2004, an evaluation was performed under the supervision and with the participation of SCE&G's management, including the CEO and CFO, of the effectiveness of the design and operation of SCE&G's disclosure controls and procedures. Based on that evaluation, SCE&G's management, including the CEO and CFO, concluded that SCE&G's disclosure controls and procedures were effective as of December 31, 2004. There has been no change in SCE&G's internal controls over financial reporting during the quarter ended December 31, 2004 that has materially affected or is reasonably likely to materially affect SCE&G's internal control over financial reporting.

PSNC Energy:

Evaluation of Disclosure Controls and Procedures:

As of December 31, 2004, an evaluation was performed under the supervision and with the participation of PSNC Energy's management, including the CEO and CFO, of the effectiveness of the design and operation of PSNC Energy's disclosure controls and procedures. Based on that evaluation, PSNC Energy's management, including the CEO and CFO, concluded that PSNC Energy's disclosure controls and procedures were effective as of December 31, 2004. There has been no change in PSNC Energy's internal controls over financial reporting during the quarter ended December 31, 2004 that has materially affected or is reasonably likely to materially affect PSNC Energy's internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

Not applicable.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

SCANA: A list of SCANA's executive officers is in Part I of this annual report at page 26. The other information required by Item 10 is incorporated herein by reference, to the captions "Election of Directors: Proposal 1—Nominees For Class III Directors," "Continuing Directors," "Board Meetings—Committees of the Board," and "Other Information—Section 16(a) Beneficial Ownership Reporting Compliance" in SCANA's definitive proxy statement for the 2005 annual meeting of shareholders which will be filed with the SEC pursuant to Regulation 14A, promulgated under the Securities Exchange Act of 1934 within 120 days after the end of SCANA's fiscal year.

CODE OF ETHICS

SCANA has adopted a code of ethics that applies to its principal executive officer, principal financial officer and principal accounting officer or controller. SCANA has posted the text of the code on its Internet website at *www.scana.com*.

DIRECTORS

SCE&G:

The directors listed below were elected April 29, 2004 (except as otherwise indicated) to hold office until the next annual meeting of SCE&G's shareholders to be held on May 5, 2005.

Name and Year First Became Director	Age	Principal Occupation; Directorships
Bill L. Amick (1990)	61	For more than five years, Chairman of the Board and Chief Executive Officer of Amick Farms, Inc., Amick Processing, Inc. and Amick Broilers, Inc., Batesburg, SC (vertically integrated broiler operation).
		Director, SCANA Corporation; PSNC Energy; Blue Cross and Blue Shield of South Carolina.
James A. Bennett (1997)	44	Since August 2002, Executive Vice President and Director of Public Affairs, First Citizens Bank, Columbia, SC.
		From May 2000 to July 2002, President and Chief Executive Officer of South Carolina Community Bank, Columbia, SC.
		From February 2000 to May 2000, Economic Development Director, First Citizens Bank.
		Director, SCANA Corporation; PSNC Energy.
William B. Bookhart, Jr. (1979)	63	For more than five years, a partner in Bookhart Farms, Elloree, SC (general farming).
		Director, SCANA Corporation; PSNC Energy.

Name and Year First Became Director	Age	Principal Occupation; Directorships
William C. Burkhardt (2000)	67	From October 2003 until May 2004 retirement, Chief Executive Officer of Capital Bank, Raleigh, NC. From 1980 until May 2000 retirement, President and Chief Executive Officer of Austin Quality Foods, Inc., Cary, NC (baked snacks production and distribution company). Director, SCANA Corporation; PSNC Energy; Capital Bank Corp., Raleigh, NC and Plaza Belmont II, Kansas City, MO.
Elaine T. Freeman* (1992)	69	For more than five years, Executive Director of ETV Endowment of South Carolina, Inc. (non-profit organization), Spartanburg, SC. Director, SCANA Corporation; PSNC Energy; National Bank of South Carolina (a member bank of Synovus Financial Corporation).
D. Maybank Hagood* (1999)	43	For more than five years, President and Chief Executive Officer of William M. Bird and Company, Inc., Charleston, SC (wholesale distributor of floor covering materials). Director, SCANA Corporation; PSNC Energy.
W. Hayne Hipp (1983)	65	For more than five years, Chairman and Chief Executive Officer of The Liberty Corporation, Greenville, SC (broadcasting holding company). Director, SCANA Corporation; PSNC Energy; The Liberty Corporation.
Lynne M. Miller* (1997)	53	For more than five years, Chief Executive Officer of Environmental Strategies Consulting LLC, formerly Environmental Strategies Corporation, Reston, VA (environmental consulting and engineering firm). Director, SCANA Corporation; PSNC Energy; Adams National Bank (a subsidiary of Abigail Adams National Bancorp, Inc.), Washington, DC.
Maceo K. Sloan* (1997)	55	For more than five years, Chairman, President and Chief Executive Officer of Sloan Financial Group, Inc. (holding company) and Chairman, Chief Executive Officer and Chief Investment Officer of NCM Capital Management Group, Inc. (investment management company), Durham, NC. Director, SCANA Corporation; PSNC Energy; M&F Bancorp, Inc.; and Trustee of Teachers Insurance Annuity Association—College Retirement Equity Fund and TIAA-CREF Funds Board, Durham, NC.
Harold C. Stowe* (1999)	58	For more than five years, President of Canal Holdings, LLC and its predecessor company, Conway, SC (forest products industry). Director, SCANA Corporation; PSNC Energy; New South Companies, Inc.; Ruddick Corporation, Charlotte, NC.

Name and Year First Became Director	Age	Principal Occupation; Directorships
William B. Timmerman (1991)	58	For more than five years, Chairman of the Board, President and Chief Executive Officer, SCANA Corporation, Columbia, SC.
		Director, SCANA Corporation; PSNC Energy; Pre Holdings, Inc.; and The Liberty Corporation, Greenville, SC.
G. Smedes York* (2000)	64	For more than five years, President and Treasurer of York Properties, Inc., Raleigh, NC. (full-service commercial and residential real estate company). Chairman of the Board of
		York Simpson Underwood (residential brokerage company) and McDonald-York, Inc. (general contractor).
		Director, SCANA Corporation; PSNC Energy.

* Indicates a member of the Audit Committee of SCE&G's board of directors. Mr. Stowe has been determined by SCE&G's board of directors to be an audit committee financial expert within the meaning of Item 401(h) of Regulation S-K. SCE&G's board of directors has also determined that Mr. Stowe is independent, as that term is used in Item 7(d)(3)(iv) of Schedule 14A under the Exchange Act.

EXECUTIVE OFFICERS OF SCE&G

SCE&G's officers are elected at the annual organizational meeting of the Board of Directors and hold office until the next such organizational meeting, unless the Board of Directors shall otherwise determine, or unless a resignation is submitted.

Name	Age	Positions Held During Past Five Years	Dates
W. B. Timmerman	58	Chairman of the Board and Chief Executive Officer	*-present
J. C. Bouknight	51	Senior Vice President—Human Resources	2004-present
		Vice President Human Resources—Dan River, Inc.—Danville, VA	*-2004
S. D. Burch	48	Senior Vice President, Natural Gas Procurement and Asset Management	2003-present
		Deputy General Counsel and Assistant Secretary	*-2003
S. A. Byrne	45	Senior Vice President-Generation, Nuclear and Fossil Hydro	2001-present
		Vice President-Nuclear Operations	*-2001
P. V. Fant	51	Senior Vice President Transmission Services, President and Chief Operating Officer-South Carolina Pipeline Corporation and SCG Pipeline, Inc.	2004-present
		Executive Vice President-South Carolina Pipeline Corporation and SCG Pipeline, Inc.	*-2004
N. O. Lorick	54	President and Chief Operating Officer	*-present
K. B. Marsh	49	Senior Vice President and Chief Financial Officer	*-present
		Controller	2000
F. P. Mood, Jr.	66	Senior Vice President, General Counsel and Assistant Secretary	2005-present
		Attorney, Haynsworth Sinkler Boyd, P.A.	*-2005

* Indicates position held at least since March 1, 2000

SECTION 16(a) BENEFICIAL OWNERSHIP REPORTING COMPLIANCE

All of SCE&G's common stock is held by its parent, SCANA Corporation. The required forms indicate that no equity securities of SCE&G are owned by its directors and officers. Based solely on a review of the copies of such forms and amendments furnished to SCE&G and written representations from the officers and directors, SCE&G believes that during 2004 all Section 16(a) filing requirements applicable to its officers, directors and greater than 10% beneficial owners were complied with except that Messrs. Bouknight, Fant and Mood each filed late his Form 3.

CODE OF ETHICS

SCE&G has a code of ethics that applies to its principal executive officer, principal financial officer and principal accounting officer or controller. The text of the code is posted on SCANA Corporation's Internet website at *www.scana.com*.

ITEM 11. EXECUTIVE COMPENSATION

SCANA: The information called for by Item 11, Executive Compensation, is incorporated herein by reference to the captions "Director Compensation," "Compensation Committee Interlocks and Insider Participation," and "Executive Compensation" in SCANA's definitive proxy statement for the 2005 annual meeting of shareholders.

SCE&G: The information called for by Item 11, Executive Compensation, is as follows:

Summary Compensation Table

		Annual Compensation			Long-Term Compensation		
					Awards	Payouts	
Name and Principal Position	Year	Salary ($)	Bonus(1) ($)	Other Annual Compensation(2) ($)	Securities Underlying Option/ SARS (#)	LTIP Payouts(3) ($)	All Other Compensation(4) ($)
W. B. Timmerman	2004	931,583(5)	948,494	7,788	—	—	101,040
Chairman, President and	2003	858,219	718,493	5,754	—	1,150,242	97,150
Chief Executive Officer—SCANA	2002	751,228	760,949	16,435	219,200	536,884	44,614
N. O. Lorick	2004	470,833	378,625	8,072	—	—	47,252
President and Chief	2003	419,808	300,036	5,962	—	325,384	44,257
Operating Officer—SCE&G	2002	376,538	317,808	16,958	77,816	145,487	22,132
K. B. Marsh	2004	470,833	378,625	1,282	—	—	47,252
Senior Vice President and	2003	419,808	300,036	928	—	325,384	44,257
Chief Financial Officer—SCANA	2002	375,384	317,808	10,183	77,816	209,432	22,063
S. A. Byrne	2004	362,728	225,660	—	—	—	33,366
Senior Vice President—	2003	323,351	180,675	—	—	169,634	30,993
Generation, Nuclear and Fossil Hydro—SCE&G	2002	285,385	191,339	9,000	42,992	146,345	16,663
H. T. Arthur*	2004	343,333	210,438	6,993	—	—	32,690
Senior Vice President,	2003	360,950	180,675	5,106	—	169,634	33,603
General Counsel and Assistant Secretary	2002	297,115	191,339	15,830	42,992	146,345	17,367

(1) Payments under the Annual Incentive Plan.

(2) For 2004, other annual compensation consists of life insurance premiums on policies owned by named executive officers.

(3) Payouts of performance share awards under the Company's Long-Term Equity Compensation Plan.

(4) All other compensation for all named executive officers consists solely of Company matching contributions to defined contribution plans, except for Mr. Arthur who retired as of January 3, 2005.

(5) Reflects actual salary paid in 2004. Base salary of $937,100 became effective on February 19, 2004.

* Information with respect to a Consulting Agreement with Mr. Arthur and SCANA Corporation is described under "Consulting Agreement and Other Benefits."

Option Exercises, Outstanding Options and Related Information

Aggregated Option/SAR Exercises in Last Fiscal Year and FY-End Option/SAR Values

(a)	(b)	(c)	(d)	(e)
			Number of Securities Underlying Unexercised Option/SARs At FY-End (#)	Value of Unexercised In-the-Money Options/ SARs at FY-End ($)(1)
Name	Shares Acquired On Exercise (#)	Value Realized ($)	Exercisable/ Unexercisable	Exercisable/ Unexercisable
W. B. Timmerman	261,534	1,956,678	50,000/73,067	594,00/868,036
N. O. Lorick	90,920	780,117	0/25,939	0/308,155
K. B. Marsh	100,215	878,895	0/25,939	0/308,155
S. A. Byrne	—	—	56,599/14,331	656,320/170,252
H. T. Arthur	—	—	56,599/14,331	656,320/170,252

(1) Based on the closing price of $39.40 per share on December 31, 2004, the last trading day of the fiscal year.

Long-Term Incentive Plans Awards

The following table lists the performance share awards and the performance unit awards made in 2004 (for potential payment in 2007) under the Long-Term Equity Compensation Plan and estimated future payouts under that plan at threshold, target and maximum levels for each of the executive officers included in the Summary Compensation Table.

LONG-TERM INCENTIVE PLANS
AWARDS IN LAST FISCAL YEAR

Name	Number of Shares, Units or Other Rights (#)	Performance or Other Period Until Maturation or Payout	Estimated Future Payouts Under Non-Stock Price-Based Plans		
			Threshold (#)	Target (#)	Maximum (#)
W. B. Timmerman	31,773(1)	2004-2006	15,887	31,773	47,660
W. B. Timmerman	21,182(2)	2004-2006	10,591	21,182	31,773
N. O. Lorick	11,057(1)	2004-2006	5,529	11,057	16,586
N. O. Lorick	7,372(2)	2004-2006	3,686	7,372	11,058
K. B. Marsh	11,057(1)	2004-2006	5,529	11,057	16,586
K. B. Marsh	7,372(2)	2004-2006	3,686	7,372	11,058
S. A. Byrne	7,991(1)	2004-2006	3,996	7,991	11,987
S. A. Byrne	5,327(2)	2004-2006	2,664	5,327	7,991
H. T. Arthur	5,992(1)	2004-2006	3,996	7,991	11,987
H. T. Arthur	3,995(2)	2004-2006	2,664	5,327	7,991

(1) Performance Share Awards

(2) Performance Unit Awards

Payouts on performance share awards will occur when SCANA's total shareholder return is in the top two-thirds of the Long-Term Equity Compensation Plan peer group for that period and will vary based on SCANA's ranking against the peer group. Executives will earn threshold payouts (50% of award) at the 33rd percentile of three-year performance. Target payouts (100% of award) will be made at the 50th percentile of three-year performance. Maximum payouts (150% of award) will be made when performance is at or above the 75th percentile of the peer group. Payments will be made on a sliding scale for performance between threshold and target and target and maximum. No payouts will be earned if performance is at less than the 33rd percentile. Awards are designated as target shares of SCANA common stock and may be paid in stock or cash or a combination of stock and cash.

Payouts on performance unit awards will occur when SCANA's three-year average growth in earnings per share from ongoing operations equals or exceeds 2%. Executives will earn threshold payments (50% of award) at 2% average growth, target payments (100% of award) at 4% average growth and maximum payouts (150% of award) at 6% average growth. No payouts will occur if average growth in earnings per share from ongoing operations over the period is less than 2%. Awards are designated as target units of SCANA common stock and may be paid in stock or cash or a combination of stock and cash.

Defined Benefit Plans

SCANA has a tax qualified defined benefit retirement plan (the "Retirement Plan"). The plan has a mandatory cash balance benefit formula for employees hired on or after January 1, 2000. Effective July 1, 2000, SCANA employees hired prior to January 1, 2000 were given the choice of remaining under the Retirement Plan's final average pay formula or switching to the cash balance formula option. All the executive officers named in the Summary Compensation Table elected to participate under the cash balance formula of the plan.

The cash balance formula is expressed in the form of a hypothetical account balance. Account balances are increased monthly by interest and compensation credits. The interest rate used for accumulating account balances is determined annually and is equal to the average rate for 30-year Treasury Notes for December of the previous calendar year. Compensation credits equal 5% of compensation under the Social Security wage base and 10% of compensation in excess of the Social Security wage base.

In addition to its Retirement Plan for all employees, SCANA has Supplemental Executive Retirement Plans ("SERPs") for certain eligible employees, including officers. A SERP is an unfunded plan that provides for benefit payments in addition to benefits payable under the qualified Retirement Plan in order to replace benefits lost in the Retirement Plan because of Internal Revenue Code maximum benefit limitations.

The estimated annual retirement benefits payable as life annuities at age 65 under the plans, based on projected compensation (assuming increases of 4% per year), to the following executive officers named in the Summary Compensation Table are as follows: Mr. Timmerman—$448,728; Mr. Lorick—$288,924; Mr. Marsh—$349,824; Mr. Byrne—$276,636. Mr. Arthur, who retired as of January 3, 2005, began receiving benefit payments from SCANA's SERP and elected to defer the distribution of his benefit from the Retirement Plan until a future date. The value of his benefit from both the SERP and the Retirement Plan as a life annuity at January 1, 2005 totaled $56,057.

Consulting Agreement and Other Benefits

On February 3, 2005, and in conjunction with the retirement of Mr. Arthur, SCANA and Mr. Arthur entered into a consulting agreement whereby Mr. Arthur will assist and advise SCANA concerning special projects for its gas transmission operations. Such projects may involve legal, regulatory or related matters. Under the agreement, SCANA will pay Mr. Arthur a consulting fee rate of $350 per hour for a guaranteed minimum of 1,000 hours per year. The agreement is effective January 3, 2005 through December 31, 2006, unless terminated earlier as provided in the agreement.

In addition, in connection with Mr. Arthur's retirement, SCANA has agreed to provide for the continuation of certain customary executive benefits, such as reimbursement of financial counseling costs and executive physical examinations, for the next two years.

Termination, Severance and Change in Control Arrangements

SCANA maintains an Executive Benefit Plan Trust. The purpose of the trust is to help retain and attract quality leadership in key SCANA positions. The trust holds SCANA contributions (if made) which may be used to pay the deferred compensation benefits of certain directors, executives and other key employees of SCANA in the event of a Change in Control (as defined in the trust). The current executive officers included in the Summary Compensation Table participate in all the plans listed below which are covered by the trust.

(1) SCANA Corporation Executive Deferred Compensation Plan

(2) SCANA Corporation Supplemental Executive Retirement Plan

(3) SCANA Corporation Long-Term Equity Compensation Plan

(4) SCANA Corporation Annual Incentive Plan

(5) SCANA Corporation Key Executive Severance Benefits Plan

(6) SCANA Corporation Supplementary Key Executive Severance Benefits Plan

The Key Executive Severance Benefits Plan and each of the plans listed under (1) through (4) provide for payment of benefits in a lump sum to the eligible participants immediately upon a Change in Control, unless the Key Executive Severance Benefits Plan is terminated prior to the Change in Control. In contrast, the Supplementary Key Executive Severance Benefits Plan is operative for a period of 24 months following a Change in Control where the Key Executive Severance Benefits Plan is inoperative because it was terminated before the Change in Control. The Supplementary Key Executive

Severance Benefits Plan provides benefits in lieu of those otherwise provided under plans (1) through (4) if: (i) the participant is involuntarily terminated from employment without "Just Cause," or (ii) the participant voluntarily terminates employment for "Good Reason" (as these terms are defined in the Supplementary Key Executive Severance Benefits Plan).

Benefit distributions relative to a Change in Control, as to which either the Key Executive Severance Benefits Plan or the Supplementary Key Executive Severance Benefits Plan is operative, include an amount equal to estimated federal, state and local income taxes and any estimated applicable excise taxes owed by the plan participants on those benefits.

The benefit distributions under the Key Executive Severance Benefits Plan would include the following three benefits:

- An amount equal to three times the sum of: (i) the participant's annual base salary in effect as of the Change in Control and (ii) the officer's target annual incentive award in effect as of the Change in Control under the Annual Incentive Plan.
- An amount equal to the projected cost for medical, long-term disability and certain life insurance coverage for three years following the Change in Control as though the participant had continued to be a SCANA employee.
- An amount equal to the participant's Supplemental Executive Retirement Plan benefit accrued to the date of the Change in Control, increased by the present value of projected benefits that would otherwise accrue under the plan (based on the plan's actuarial assumptions) assuming that the participant remained employed until reaching age 65 and offset by the value of the participant's Retirement Plan benefit.

Additional benefits payable upon a Change in Control where the Key Executive Severance Benefits Plan is operable are:

- A benefit distribution of all amounts credited to the participant's Executive Deferred Compensation Plan account as of the date of the Change in Control.
- A benefit distribution under the Long-Term Equity Compensation Plan equal to 100% of the target performance share and performance unit awards for all performance periods not completed as of the date of the Change in Control, if any.
- Under the Long-Term Equity Compensation Plan, all nonqualified stock options awarded would become immediately exercisable and remain exercisable throughout their term.
- A benefit distribution under the Annual Incentive Plan equal to 100% of the target award in effect as of the date of the Change in Control.

The benefits and their respective amounts under the Supplementary Key Executive Severance Benefits Plan would be the same except that the benefits payable with respect to the Executive Deferred Compensation Plan would be increased by the prime rate published in the Wall Street Journal most nearly preceding the date of the Change in Control plus 3% calculated until the end of the month preceding the month in which the benefits are distributed.

Compensation Committee Interlocks and Insider Participation

During 2004, decisions on various elements of executive compensation were made by the Human Resources Committee. No officer, employee or former officer of SCANA or any of its subsidiaries served as a member of the Human Resources Committee.

The names of the persons who serve on the Human Resources Committee can be found at Item 12, Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Information.

Director Compensation

Board Fees

Officers of SCANA who are also directors do not receive additional compensation for their service as directors. Since July 1, 2004, compensation for non-employee directors consist of the following:

- an annual retainer of $36,000 (60% of the annual retainer fee is paid in shares of SCANA common stock);
- $3,500 for each board meeting attended;
- $3,000 for attendance at a committee meeting held on a day other than a day a regular meeting of the Board is held;
- $300 for participation in a telephone conference meeting of 30 minutes or less, and $600 for participation in a telephone conference exceeding 30 minutes;
- $3,000 for attendance at an all-day conference; and
- reimbursement for expenses incurred in connection with all of the above.

Director Compensation and Deferral Plans

Since January 1, 2001, non-employee director compensation and deferrals have been governed by the SCANA Corporation Director Compensation and Deferral Plan. Amounts deferred by directors in previous years under the SCANA Voluntary Deferral Plan continue to be governed by that plan. During 2004, the only director remaining in the Voluntary Deferral Plan was Mr. Bennett, whose account was credited with interest of $2,598 for the year.

Under the Director Compensation and Deferral Plan, a director may elect to defer the 60% of the annual retainer fee required to be paid in SCANA common stock in a hypothetical investment in SCANA common stock, with distribution from the plan to be ultimately payable in actual shares of SCANA common stock. A director may also elect to defer the 40% of the annual retainer fee not required to be paid in stock and up to 100% of meeting attendance and conference fees with distribution from the plan to be ultimately payable in either SCANA common stock or cash. Amounts payable in SCANA common stock accrue earnings during the deferral period at SCANA's dividend rate, which amount may be elected to be paid in cash when accrued or retained to invest in additional hypothetical shares of SCANA common stock. Amounts payable in cash accrue interest earnings until paid.

During 2004, Messrs. Amick, Bennett, Burkhardt, Hipp, Sloan, Stowe and York and Ms. Miller elected to defer 100% of their compensation and earnings under the Director Compensation and Deferral Plan so as to acquire hypothetical shares of SCANA common stock. Mr. Hagood elected to defer 60% of his annual retainer and earnings under the plan to acquire hypothetical shares of SCANA common stock.

Endowment Plan

Upon election to a second term, a director becomes eligible to participate in the SCANA Director Endowment Plan, which provides for SCANA to make a tax deductible, charitable contribution totaling $500,000 to institutions of higher education designated by the director. The plan is intended to reinforce SCANA's commitment to quality higher education and to enhance its ability to attract and retain qualified Board members. A portion is contributed upon retirement of the director and the remainder upon the director's death. The plan is funded in part through insurance on the lives of the directors.

Designated institutions of higher education in South Carolina, North Carolina and Georgia must be approved by SCANA's Chief Executive Officer. Institutions in other states must be approved by the Human Resources Committee. The designated institutions are reviewed on an annual basis by the Chief Executive Officer to assure compliance with the intent of the program.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

SCANA: Information called for by this Item is incorporated herein by reference to the caption "Share Ownership of Directors, Nominees and Executive Officers" and "Five Percent Ownership of SCANA Common Stock" in SCANA's definitive proxy statement for the 2005 annual meeting of shareholders.

Equity securities issuable under SCANA's compensation plans at December 31, 2004 are summarized as follows:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by security holders:			
Long-Term Equity Compensation Plan	730,447	$27.49	3,212,896
Non-Employee Director Compensation Plan	—	n/a	154,565
Equity compensation plans not approved by security holders	n/a	n/a	n/a
Total	730,447	$27.49	3,367,461

SCE&G: All of the outstanding voting securities of SCE&G are owned by SCANA. The following table lists shares of SCANA common stock beneficially owned on January 20, 2005 by each director and each person named in the Summary Compensation table in Item 11, Executive Compensation.

SHARE OWNERSHIP OF DIRECTORS, NOMINEES AND EXECUTIVE OFFICERS

Name	Amount and Nature of Beneficial Ownership of SCANA Common Stock*(1)(2)(3)(4)(5)	Name	Amount and Nature of Beneficial Ownership of SCANA Common Stock*(1)(2)(3)(4)(5)
B. L. Amick(6)	10,865	W. H. Hipp	4,896
H. T. Arthur	89,091	N. O. Lorick	44,686
J. A. Bennett	2,523	K. B. Marsh	44,020
W. B. Bookhart, Jr.(6)	24,337	L. M. Miller	3,603
W. C. Burkhardt(6)	12,142	M. K. Sloan(6)	4,678
S. A. Byrne	78,784	H. C. Stowe(6)	2,500
E. T. Freeman	11,568	W. B. Timmerman	180,608
D. M. Hagood(6)	1,408	G. S. York	12,707

* Each of the above owns less than 1% of the shares outstanding.

All directors and executive officers as a group (20 persons) total 724,483 shares, including 346,252 shares subject to currently exercisable options and options that will become exercisable within 60 days. Total percent of class outstanding is less than one percent.

(1) Includes 6,864 shares owned by close relatives of Mr. Bookhart, the beneficial ownership of which he disclaims and 182 shares owned by close relatives of Mr. Lorick.

(2) Includes shares purchased through January 20, 2005, by the Trustee under SCANA's Stock Purchase Savings Plan.

(3) Hypothetical shares acquired under the SCANA Director Compensation and Deferral Plan are not included in the above table. As of January 20, 2005, each of the following directors had acquired under the plan, the number of hypothetical shares following his or her name: Messrs. Amick—9,998, Bennett—9,781, Burkhardt—11,835, Hagood—2,865, Hipp—9,701, Sloan—10,663, Stowe—10,034, York—11,123 and Ms. Miller—11,283.

(4) Includes shares subject to options that are currently exercisable or that will become exercisable within 60 days in the following amounts: Messrs. Timmerman—123,067; Lorick—25,939; Marsh—25,939, Byrne—70,930 and Arthur—70,930.

(5) Hypothetical shares acquired under the SCANA Executive Deferred Compensation Plan are not included in the above table. As of January 6, 2005, each of the following officers had acquired under the plan, the number of hypothetical shares following his or her name: Messrs. Timmerman—31,041; Lorick—6,855; Marsh—4,762, Byrne—3,993 and Arthur—5,547.

(6) Human Resources Committee member.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

SCANA: The information called for by Item 13, Certain Relationships and Related Transactions, is incorporated herein by reference to the caption "Related Transactions" in SCANA's definitive proxy statement for the 2005 annual meeting of shareholders.

Notwithstanding anything to the contrary set forth in any of the Company's previous filings under the Securities Act of 1933, as amended, or the Securities Exchange Act of 1934, as amended, that might incorporate by reference future filings, including this Annual Report on Form 10-K, in whole or in part, the "Report on Executive Compensation", the "Performance Graph" and the "Audit Committee Report" included in SCANA's definitive proxy statement for the 2005 annual meeting of shareholders shall not be incorporated by reference into any such filings.

SCE&G: During 2004, SCANA incurred advertising expenses of $75,412 (including the value of non-utility in-kind services provided by SCANA and its subsidiaries) for services provided by subsidiaries of The Liberty Corporation. SCANA's management believes that these services, a significant portion of which were arranged through the use of an independent third-party advertising agency, were provided at competitive market rates.

Mr. Hipp is Chairman and Chief Executive Officer and a director of The Liberty Corporation. It is anticipated that similar transactions will occur in the future.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

SCANA: The information required by Item 14 is incorporated herein by reference to "Proposal 3—Approval of Appointment of Independent Registered Public Accounting Firm" in SCANA's definitive proxy statement for the 2005 annual meeting of shareholders.

SCE&G and PSNC Energy:

SCANA's Audit Committee Charter requires the Audit Committee to pre-approve all auditing services and permitted non-audit services (including the fees and terms thereof) to be performed by the external auditors. Pursuant to a policy adopted by the Audit Committee, the Committee Chairman may pre-approve the rendering of services on behalf of the Audit Committee.

Independent Registered Public Accounting Firm Fees

The following table sets forth the aggregate fees billed to SCE&G and PSNC Energy for the fiscal years ended December 31, 2004 and 2003 by Deloitte & Touche LLP, the member firms of Deloitte Touche Tohmatsu, and their respective affiliates.

	2004		2003	
	SCE&G	PSNC Energy	SCE&G	PSNC Energy
Audit Fees(1)	$1,317,132	$271,423	$ 747,716	$143,661
Audit Related Fees(2)	133,787	19,329	348,301	72,200
Tax Fees(3)	2,582	535	32,053	2,813
Total Fees	$1,453,501	$291,287	$1,128,070	$218,674

(1) Fees for audit services billed in 2004 and 2003 consisted of audits of the companies' annual financial statements, reviews of the companies quarterly financial statements, comfort letters, statutory and regulatory audits, consents and other services related to the Securities and Exchange Commission ("SEC"), accounting research and SCANA Corporation's audit of internal controls over financial reporting in 2004.

(2) Includes employee benefit plan audits for 2004 and 2003 and Sarbanes Oxley Section 404 readiness assistance in 2003.

(3) Includes tax compliance and tax services.

In 2004 and 2003 all of the Audit Fees, Audit Related Fees and Tax Fees were approved by the Audit Committee.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed or furnished as a part of this Form 10-K:

(1) Financial Statements and Schedules:

The Report of Independent Registered Public Accounting Firm on the financial statements for SCANA, SCE&G and PSNC Energy are listed under Item 8 herein.

The financial statements and supplementary financial data filed as part of this report for SCANA, SCE&G and PSNC Energy are listed under Item 8 herein.

The financial statement schedules filed as part of this report for SCANA, SCE&G and PSNC Energy begin on the following page.

(2) Exhibits

Exhibits required to be filed or furnished with this Annual Report on Form 10-K are listed in the Exhibit Index following the signature page. Certain of such exhibits which have heretofore been filed with the Securities and Exchange Commission and which are designated by reference to their exhibit number in prior filings are incorporated herein by reference and made a part hereof.

Pursuant to Rule 15d-21 promulgated under the Securities Exchange Act of 1934, the annual report for SCANA's employee stock purchase plan will be furnished under cover of Form 10-K/A to the Commission when the information becomes available.

As permitted under Item 601(b)(4)(iii) of Regulation S-K, instruments defining the rights of holders of long-term debt of less than 10% of the total consolidated assets of SCANA, for itself and its subsidiaries, of SCE&G, for itself and its consolidated affiliates, and of PSNC Energy, for itself and its subsidiaries, have been omitted and SCANA, SCE&G and PSNC Energy agree to furnish a copy of such instruments to the Commission upon request.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

SCANA CORPORATION

BY: /s/ W. B. TIMMERMAN

W. B. Timmerman, *Chairman of the Board, President, Chief Executive Officer and Director*

DATE: February 28, 2005

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signatures of the undersigned shall be deemed to relate only to matters having reference to the registrant and any subsidiaries thereof.

/s/ W. B. TIMMERMAN

W. B. Timmerman, *Chairman of the Board, President, Chief Executive Officer and Director (Principal Executive Officer)*

/s/ K. B. MARSH

K. B. Marsh, *Senior Vice President and Chief Financial Officer (Principal Financial Officer)*

/s/ J. E. SWAN

J. E. Swan, *Controller (Principal Accounting Officer)*

Other Directors*:

B. L. Amick	W. M. Hipp
J. A. Bennett	L. M. Miller
W. B. Bookhart, Jr.	M. K. Sloan
W. C. Burkhardt	H. C. Stowe
E. T. Freeman	G. S. York
D. M. Hagood	

* Signed on behalf of each of these persons by Kevin B. Marsh, Attorney-in-Fact

DATE: February 28, 2005

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries or consolidated affiliates thereof.

SOUTH CAROLINA ELECTRIC & GAS COMPANY

BY: /s/ N. O. LORICK

N. O. Lorick
President and Chief Operating Officer

DATE: February 28, 2005

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signatures of the undersigned shall be deemed to relate only to matters having reference to the registrant and any subsidiaries or consolidated affiliates thereof.

/s/ W. B. TIMMERMAN

W. B. Timmerman, *Chairman of the Board, Chief Executive Officer and Director (Principal Executive Officer)*

/s/ K. B. MARSH

K. B. Marsh, *Senior Vice President and Chief Financial Officer (Principal Financial Officer)*

/s/ J. E. SWAN

J. E. Swan, *Controller (Principal Accounting Officer)*

Other Directors*:

B. L. Amick	W. M. Hipp
J. A. Bennett	L. M. Miller
W. B. Bookhart, Jr.	M. K. Sloan
W. C. Burkhardt	H. C. Stowe
E. T. Freeman	G. S. York
D. M. Hagood	

* Signed on behalf of each of these persons by Kevin B. Marsh, Attorney-in-Fact

DATE: February 28, 2005

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INCORPORATED

BY: /s/ JERRY W. RICHARDSON

Jerry W. Richardson
President and Chief Operating Officer

DATE: February 28, 2005

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signatures of the undersigned shall be deemed to relate only to matters having reference to the registrant and any subsidiaries thereof.

/s/ W. B. TIMMERMAN

W. B. Timmerman, *Chairman of the Board, Chief Executive Officer and Director (Principal Executive Officer)*

/s/ K. B. MARSH

K. B. Marsh, *Senior Vice President and Chief Financial Officer (Principal Financial Officer)*

/s/ J. E. SWAN

J. E. Swan, *Controller (Principal Accounting Officer)*

Other Directors*:

B. L. Amick	W. M. Hipp
J. A. Bennett	L. M. Miller
W. B. Bookhart, Jr.	M. K. Sloan
W. C. Burkhardt	H. C. Stowe
E. T. Freeman	G. S. York
D. M. Hagood	

* Signed on behalf of each of these persons by Kevin B. Marsh, Attorney-in-Fact

DATE: February 28, 2005

EXHIBIT INDEX

Exhibit No.	Applicable to Form 10-K of: SCANA	SCE&G	PSNC Energy	Description
3.01	X			Restated Articles of Incorporation of SCANA Corporation as adopted on April 26, 1989 (Filed as Exhibit 3-A to Registration Statement No. 33-49145 and incorporated by reference herein)
3.02	X			Articles of Amendment dated April 27, 1995 (Filed as Exhibit 4-B to Registration Statement No. 33-62421 and incorporated by reference herein)
3.03		X		Restated Articles of Incorporation of South Carolina Electric & Gas Company, as adopted on May 3, 2001 (Filed as Exhibit 3.01 to Registration Statement No. 333-65460 and incorporated by reference herein)
3.04		X		Articles of Amendment effective as of the dates indicated below and filed as exhibits to the Registration Statements or Exchange Act reports set forth below and are incorporated by reference herein May 22, 2001 Exhibit 3.02 to Registration No. 333-65460 June 14, 2001 Exhibit 3.04 to Registration No. 333-65460 August 30, 2001 Exhibit 3.05 to Registration No. 333-101449 March 13, 2002 Exhibit 3.06 to Registration No. 333-101449 May 9, 2002 Exhibit 3.07 to Registration No. 333-101449 June 4, 2002 Exhibit 3.08 to Registration No. 333-101449 August 12, 2002 Exhibit 3.09 to Registration No. 333-101449 March 13, 2003 Exhibit 3.03 to Registration No. 333-108760 May 22, 2003 Exhibit 3.04 to Registration No. 333-108760 June 18, 2003 Exhibit 3.05 to Registration No. 333-108760 August 7, 2003 Exhibit 3.06 to Registration No. 333-108760 May 18, 2004 Exhibit 3.05 to Form 10-Q for the quarter ended June 30, 2004 June 18, 2004 Exhibit 3.06 to Form 10-Q for the quarter ended June 30, 2004 August 12, 2004 Exhibit 3.05 to Form 10-Q for the quarter ended Sept. 30, 2004
3.05		X		Articles of Amendment dated February 26, 2004 (Filed herewith)
3.06		X		Articles of Correction filed on June 1, 2001 correcting May 22, 2001 Articles of Amendment (Filed as Exhibit 3.03 to Registration Statement No. 333-65460 and incorporated by reference herein)
3.07		X		Articles of Correction filed on February 17, 2004 correcting Articles of Amendment for the dates indicated below and filed as exhibits to the 2003 Form 10-K as set forth below and are incorporated by reference herein May 3, 2001 Exhibit 3.06 May 22, 2001 Exhibit 3.07 June 14, 2001 Exhibit 3.08 August 30, 2001 Exhibit 3.09 March 13, 2002 Exhibit 3.10 May 9, 2002 Exhibit 3.11 June 4, 2002 Exhibit 3.12 August 12, 2002 Exhibit 3.13 March 13, 2003 Exhibit 3.14 May 22, 2003 Exhibit 3.15 June 18, 2003 Exhibit 3.16 August 7, 2003 Exhibit 3.17
3.08	X			By-Laws of SCANA as revised and amended on December 13, 2000 (Filed as Exhibit 3.01 to Registration Statement No. 333-68266 and incorporated by reference herein)
3.09		X		By-Laws of SCE&G as revised and amended on February 22, 2001 (Filed as Exhibit 3.05 to Registration Statement No. 333-65460 and incorporated by reference herein)

Exhibit No.	Applicable to Form 10-K of			Description
	SCANA	SCE&G	PSNC Energy	
3.10			X	By-Laws of PSNC Energy as revised and amended on February 22, 2001 (Filed as Exhibit 3.01 to Registration Statement No. 333-68516 and incorporated by reference herein)
4.01	X	X		Articles of Exchange of South Carolina Electric & Gas Company and SCANA Corporation (Filed as Exhibit 4-A to Post-Effective Amendment No. 1 to Registration Statement No. 2-90438 and incorporated by reference herein)
4.02	X			Indenture dated as of November 1, 1989 between SCANA Corporation and The Bank of New York, as Trustee (Filed as Exhibit 4-A to Registration No. 33-32107 and incorporated by reference herein)
4.03	X	X		Indenture dated as of January 1, 1945, between the South Carolina Power Company and Central Hanover Bank and Trust Company, as Trustee, as supplemented by three Supplemental Indentures dated respectively as of May 1, 1946, May 1, 1947 and July 1, 1949 (Filed as Exhibit 2-B to Registration Statement No. 2-26459 and incorporated by reference herein)
4.04	X	X		Fourth Supplemental Indenture dated as of April 1, 1950, to Indenture referred to in Exhibit 4.03, pursuant to which SCE&G assumed said Indenture (Exhibit 2-C to Registration Statement No. 2-26459 and incorporated by reference herein)
4.05	X	X		Fifth through Fifty-third Supplemental Indenture referred to in Exhibit 4.03 dated as of the dates indicated below and filed as exhibits to the Registration Statements set forth below and are incorporated by reference herein

December 1, 1950	Exhibit 2-D	to Registration No. 2-26459
July 1, 1951	Exhibit 2-E	to Registration No. 2-26459
June 1, 1953	Exhibit 2-F	to Registration No. 2-26459
June 1, 1955	Exhibit 2-G	to Registration No. 2-26459
November 1, 1957	Exhibit 2-H	to Registration No. 2-26459
September 1, 1958	Exhibit 2-I	to Registration No. 2-26459
September 1, 1960	Exhibit 2-J	to Registration No. 2-26459
June 1, 1961	Exhibit 2-K	to Registration No. 2-26459
December 1, 1965	Exhibit 2-L	to Registration No. 2-26459
June 1, 1966	Exhibit 2-M	to Registration No. 2-26459
June 1, 1967	Exhibit 2-N	to Registration No. 2-29693
September 1, 1968	Exhibit 4-O	to Registration No. 2-31569
June 1, 1969	Exhibit 4-C	to Registration No. 33-38580
December 1, 1969	Exhibit 4-O	to Registration No. 2-35388
June 1, 1970	Exhibit 4-R	to Registration No. 2-37363
March 1, 1971	Exhibit 2-B-17	to Registration No. 2-40324
January 1, 1972	Exhibit 2-B	to Registration No. 33-38580
July 1, 1974	Exhibit 2-A-19	to Registration No. 2-51291
May 1, 1975	Exhibit 4-C	to Registration No. 33-38580
July 1, 1975	Exhibit 2-B-21	to Registration No. 2-53908
February 1, 1976	Exhibit 2-B-22	to Registration No. 2-55304
December 1, 1976	Exhibit 2-B-23	to Registration No. 2-57936
March 1, 1977	Exhibit 2-B-24	to Registration No. 2-58662
May 1, 1977	Exhibit 4-C	to Registration No. 33-38580
February 1, 1978	Exhibit 4-C	to Registration No. 33-38580
June 1, 1978	Exhibit 2-A-3	to Registration No. 2-61653
April 1, 1979	Exhibit 4-C	to Registration No. 33-38580
June 1, 1979	Exhibit 2-A-3	to Registration No. 33-38580
April 1, 1980	Exhibit 4-C	to Registration No. 33-38580
June 1, 1980	Exhibit 4-C	to Registration No. 33-38580
December 1, 1980	Exhibit 4-C	to Registration No. 33-38580
April 1, 1981	Exhibit 4-D	to Registration No. 33-38580
June 1, 1981	Exhibit 4-D	to Registration No. 33-49421
March 1, 1982	Exhibit 4-D	to Registration No. 2-73321

Exhibit No.	Applicable to Form 10-K of SCANA	SCE&G	PSNC Energy	Description
				April 15, 1982 Exhibit 4-D to Registration No. 33-49421 May 1, 1982 Exhibit 4-D to Registration No. 33-49421 December 1, 1984 Exhibit 4-D to Registration No. 33-49421 December 1, 1985 Exhibit 4-D to Registration No. 33-49421 June 1, 1986 Exhibit 4-D to Registration No. 33-49421 February 1, 1987 Exhibit 4-D to Registration No. 33-49421 September 1, 1987 Exhibit 4-D to Registration No. 33-49421 January 1, 1989 Exhibit 4-D to Registration No. 33-49421 January 1, 1991 Exhibit 4-D to Registration No. 33-49421 July 15, 1991 Exhibit 4-D to Registration No. 33-49421 August 15, 1991 Exhibit 4-D to Registration No. 33-49421 April 1, 1993 Exhibit 4-E to Registration No. 33-49421 July 1, 1993 Exhibit 4-D to Registration No. 33-49421 May 1, 1999 Exhibit 4.04 to Registration No. 333-86387
4.06	X	X		Indenture dated as of April 1, 1993 from South Carolina Electric & Gas Company to NationsBank of Georgia, National Association (Filed as Exhibit 4-F to Registration Statement No. 33-49421 and incorporated by reference herein)
4.07	X	X		First Supplemental Indenture to Indenture referred to in Exhibit 4.06 dated as of June 1, 1993 (Filed as Exhibit 4-G to Registration Statement No. 33-49421 and incorporated by reference herein)
4.08	X	X		Second Supplemental Indenture to Indenture referred to in Exhibit 4.06 dated as of June 15, 1993 (Filed as Exhibit 4-G to Registration Statement No. 33-57955 and incorporated by reference herein)
4.09	X		X	Indenture dated as of January 1, 1996 between PSNC and First Union National Bank of North Carolina, as Trustee (Filed as Exhibit 4.08 to Registration Statement No. 333-45206 and incorporated by reference herein)
4.10	X		X	First through Fourth Supplemental Indenture referred to in Exhibit 4.09 dated as of the dates indicated below and filed as exhibits to the Registration Statements whose file numbers are set forth below and are incorporated by reference herein January 1, 1996 Exhibit 4.09 to Registration No. 333-45206 December 15, 1996 Exhibit 4.10 to Registration No. 333-45206 February 10, 2000 Exhibit 4.11 to Registration No. 333-45206 February 12, 2001 Exhibit 4.05 to Registration No. 333-68516
4.11	X		X	PSNC $150 million medium-term note issued February 16, 2001 (Filed as Exhibit 4.06 to Registration Statement No. 333-68516 and incorporated by reference herein)
*10.01	X	X	X	SCANA Executive Deferred Compensation Plan as amended February 20, 2003 (Filed as Exhibit 10.01 to Form 10-Q for the quarter ended June 30, 2003 and incorporated by reference herein)
*10.02	X	X	X	SCANA Director Compensation and Deferral Plan as amended January 1, 2001 (Filed as Exhibit 4.03 to Registration Statement No. 333-18973 and incorporated by reference herein)
*10.03	X	X	X	Amendment to SCANA Director Compensation and Deferral Plan adopted April 29, 2004 (Filed as Exhibit 10.03 to Form 10-Q for the quarter ended March 31, 2004 and incorporated by reference herein)
*10.04	X	X	X	SCANA Supplementary Executive Retirement Plan as amended July 1, 2001 (Filed as Exhibit 10.02 to Form 10-Q for the quarter ended September 30, 2001 and incorporated by reference herein)
*10.05	X	X	X	SCANA Key Executive Severance Benefits Plan as amended July 1, 2001 (Filed as Exhibit 10.03 to Form 10-Q for the quarter ended September 30, 2001 and incorporated by reference herein)

Exhibit No.	Applicable to Form 10-K of SCANA	SCE&G	PSNC Energy	Description
*10.06	X	X	X	SCANA Supplementary Key Severance Benefits Plan as amended July 1, 2001 (Filed as Exhibit 10.03a to Form 10-Q for the quarter ended September 30, 2001 and incorporated by reference herein)
*10.07	X	X	X	SCANA Long-Term Equity Compensation Plan dated January 2000 (Filed as Exhibit 4.04 to Registration Statement No. 333-37398 and incorporated by reference herein)
*10.08	X	X	X	Amendment to SCANA Long-Term Equity Compensation Plan adopted April 29, 2004 (Filed as Exhibit 10.08 to Form 10-Q for the quarter ended March 31, 2004 and incorporated by reference herein)
*10.09	X	X	X	Description of SCANA Whole Life Option (Filed as Exhibit 10-F to Form 10-K for the year ended December 31, 1991, under cover of Form SE, File No. 1-8809 and incorporated by reference herein)
*10.10	X	X	X	Description of SCANA Corporation Executive Annual Incentive Plan (Filed as Exhibit 10-G to Form 10-K for the year ended December 31, 1991, under cover of Form SE, File No. 1-8809 and incorporated by reference herein)
10.11			X	Operating Agreement of Pine Needle LNG Company, LLC dated August 8, 1995 (Filed as Exhibit 10.01 to Registration Statement No. 333-45206 and incorporated by reference herein)
10.12			X	Amendment to Operating Agreement of Pine Needle LNG Company, LLC dated October 1, 1995 (Filed as Exhibit 10.02 to Registration Statement No. 333-45206 and incorporated by reference herein)
10.13			X	Amended Operating Agreement of Cardinal Extension Company, LLC dated December 19, 1996 (Filed as Exhibit 10.03 to Registration Statement No. 333-45206 and incorporated by reference herein)
10.14			X	Amended Construction, Operation and Maintenance Agreement by and between Cardinal Operating Company and Cardinal Extension Company, LLC dated December 19, 1996 (Filed as Exhibit 10.04 to Registration Statement No. 333-45206 and incorporated by reference herein)
10.15			X	Service Agreement between PSNC and SCANA Services, Inc., effective January 1, 2004 (Filed as Exhibit 10.15 to Form 10-Q for the quarter ended March 31, 2004 and incorporated by reference herein)
10.16			X	Service Agreement between SCE&G and SCANA Services, Inc., effective January 1, 2004 (Filed as Exhibit 10.16 to Form 10-Q for the quarter ended March 31, 2004 and incorporated by reference herein)
*10.17	X	X	X	Consulting Agreement with H. Thomas Arthur (Filed as Exhibit 99.01 to Form 8-K dated February 3, 2005 and incorporated by reference herein)
*10.18	X	X	X	Description of Amendment to SCANA Corporation Executive Annual Incentive Plan (Filed on Form 8-K dated February 23, 2005 and incorporated by reference herein)
12.01	X			Statement Re Computation of Ratios
12.02		X		Statement Re Computation of Ratios
12.03			X	Statement Re Computation of Ratios
21.01	X			Subsidiaries of the registrant (Filed herewith under the heading "Corporate Structure" in Part I, Item I of this Form 10-K and incorporated by reference herein)
23.01	X			Consents of Experts and Counsel (Consent of Independent Registered Public Accounting Firm)
23.02		X		Consents of Experts and Counsel (Consent of Independent Registered Public Accounting Firm)

Exhibit No.	Applicable to Form 10-K of SCANA	SCE&G	PSNC Energy	Description
23.03			X	Consents of Experts and Counsel (Consent of Independent Registered Public Accounting Firm)
24.01	X	X	X	Power of Attorney (Filed herewith)
31.01	X			Certification of Principal Executive Officer Required by Rule 13a-14 (Filed herewith)
31.02	X			Certification of Principal Financial Officer Required by Rule 13a-14 (Filed herewith)
31.03		X		Certification of Principal Executive Officer Required by Rule 13a-14 (Filed herewith)
31.04		X		Certification of Principal Financial Officer Required by Rule 13a-14 (Filed herewith)
31.05			X	Certification of Principal Executive Officer Required by Rule 13a-14 (Filed herewith)
31.06			X	Certification of Principal Financial Officer Required by Rule 13a-14 (Filed herewith)
32.01	X			Certification of Principal Executive Officer Pursuant to 18 U.S.C. Section 1350 (Furnished herewith)
32.02	X			Certification of Principal Financial Officer Pursuant to 18 U.S.C. Section 1350 (Furnished herewith)
32.03		X		Certification of Principal Executive Officer Pursuant to 18 U.S.C. Section 1350 (Furnished herewith)
32.04		X		Certification of Principal Financial Officer Pursuant to 18 U.S.C. Section 1350 (Furnished herewith)
32.05			X	Certification of Principal Executive Officer Pursuant to 18 U.S.C. Section 1350 (Furnished herewith)
32.06			X	Certification of Principal Financial Officer Pursuant to 18 U.S.C. Section 1350 (Furnished herewith)

* Management Contract or Compensatory Plan or Arrangement

Exhibit 12.01

SCANA CORPORATION
CALCULATION OF RATIOS
FOR THE YEAR ENDED DECEMBER 31, 2004
(Dollars in Millions)

CALCULATION OF BOND RATIO:

Net earnings(1)		$711.1
Divide by annualized interest charges on:		
Bonds authenticated under SCE&G's First and Refunding Mortgage Bond Indenture	$ 11.8	
Other indebtedness(1)	112.5	
Total annualized interest charges		124.3
Bond Ratio		5.72

(1) As defined under SCE&G's First and Refunding Mortgage Bond Indenture, dated January 1, 1945 (Old Mortgage).

CALCULATION OF NEW BOND RATIO:

Net earnings(2)		$691.9
Divide by annualized interest charges on:		
Bonds authenticated under SCE&G's First Mortgage Bond Indenture	$111.0	
Other indebtedness(2)	13.3	
Total annualized interest charges		124.3
New Bond Ratio		5.57

(2) As defined under SCE&G's Collateral Trust Mortgage Indenture, dated April 1, 1993 (New Mortgage).

CALCULATION OF PREFERRED STOCK RATIO:

Net earnings(3)		$225.2
Divide by annualized interest charges on:		
Bonds outstanding under SCE&G's mortgage bond indentures	$124.3	
Preferred dividend requirements	7.3	
Total annualized interest charges		131.6
Preferred Stock Ratio		1.71

(3) As defined under SCE&G's Restated Articles of Incorporation.

SCANA CORPORATION
COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES
For Each of the Five Years Ended December 31, 2004
(Dollars in Millions)

	Years Ended December 31,				
	2004	2003	2002	2001	2000
Fixed Charges as defined:					
Interest on long-term debt	$206.9	$206.1	$206.1	$ 227.5	$226.1
Amortization of debt premium, discount and expense (net)	5.4	4.9	5.1	6.4	4.4
Interest component on rentals	3.9	3.6	3.4	1.8	1.2
Preference security dividend requirement	11.9	13.6	15.7	15.7	15.8
Total Fixed Charges (A)	$228.1	$228.2	$230.3	$ 251.4	$247.5
Earnings as defined:					
Pretax income (loss) from continuing operations	$387.1	$426.2	$ (94.3)	$ 855.4	$373.7
Total fixed charges above	228.1	228.2	230.3	251.4	247.5
Pretax equity earnings of investees	(5.4)	(5.2)	(5.8)	(3.7)	0.6
Cash distributions from equity investees	7.4	7.7	7.8	11.2	5.9
Preference security dividend requirements from above	(11.9)	(13.6)	(15.7)	(15.7)	(15.8)
Total Earnings (B)	$605.3	$643.3	$122.3	$1,098.6	$611.9
Ratio of Earnings to Fixed Charges (B/A)	2.65	2.82	.53	4.37	2.47

For 2002, an additional $106.8 million in income before income taxes would be needed to obtain a ratio of 1.0. See Note 1G to the consolidated financial statements.

Exhibit 12.02

SOUTH CAROLINA ELECTRIC & GAS COMPANY
CALCULATION OF RATIOS
FOR THE YEAR ENDED DECEMBER 31, 2004
(Dollars in Millions)

CALCULATION OF BOND RATIO:

Net earnings(1)		$711.1
Divide by annualized interest charges on:		
Bonds authenticated under SCE&G's First and Refunding Mortgage Bond Indenture	$ 11.8	
Other indebtedness(1)	112.5	
Total annualized interest charges		124.3
Bond Ratio		5.72

(1) As defined under SCE&G's First and Refunding Mortgage Bond Indenture, dated January 1, 1945 (Old Mortgage).

CALCULATION OF NEW BOND RATIO:

Net earnings(2)		$691.9
Divide by annualized interest charges on:		
Bonds authenticated under SCE&G's First Mortgage Bond Indenture	$111.0	
Other indebtedness(2)	13.3	
Total annualized interest charges		124.3
New Bond Ratio		5.57

(2) As defined under SCE&G's Collateral Trust Mortgage Indenture, dated April 1, 1993 (New Mortgage).

CALCULATION OF PREFERRED STOCK RATIO:

Net earnings(3)		$225.2
Divide by annualized interest charges on:		
Bonds outstanding under SCE&G's mortgage bond indentures	$124.3	
Preferred dividend requirements	7.3	
Total annualized interest charges		131.6
Preferred Stock Ratio		1.71

(3) As defined under SCE&G's Restated Articles of Incorporation.

SOUTH CAROLINA ELECTRIC & GAS COMPANY
COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES
For Each of the Five Years Ended December 31, 2004
(Dollars in Millions)

	Years Ended December 31,				
	2004	**2003**	**2002**	**2001**	**2000**
Fixed Charges as defined:					
Interest on long-term debt	$144.2	$143.7	$132.4	$123.4	$113.7
Amortization of debt premium, discount and expense (net)	4.2	3.5	3.0	2.9	2.6
Interest component on rentals	3.3	2.9	2.7	1.8	1.2
Preference security dividend requirement	—	1.7	3.8	3.8	3.8
Total Fixed Charges (A)	$151.7	$151.8	$141.9	$131.9	$121.3
Earnings as defined:					
Pretax income from continuing operations	$502.6	$477.3	$468.8	$470.1	$491.7
Total fixed charges above	151.7	151.8	141.9	131.9	121.3
Preference security dividend requirements from above	—	(1.7)	(3.8)	(3.8)	(3.8)
Total Earnings (B)	$654.3	$627.4	$606.9	$598.2	$609.2
Ratio of Earnings to Fixed Charges (B/A)	4.31	4.13	4.28	4.54	5.02

Exhibit 12.03

PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INCORPORATED
COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES
For Each of the Five Years Ended December 31, 2004
(Dollars in Millions)

	Years Ended December 31,				
	2004	2003	2002	2001	2000
Fixed Charges as defined:					
Interest on long-term debt	$18.8	$19.1	$ 19.8	$20.3	$12.4
Interest expense	2.2	1.7	1.6	2.4	8.0
Amortization of debt discount	0.2	0.2	0.3	0.3	0.2
Interest components on rentals	0.3	0.3	0.3	0.3	0.1
Total Fixed Charges (A)	$21.5	$21.3	$ 22.0	$23.3	$20.7
Earnings as defined:					
Pretax income (loss) from continuing operations	$38.3	$50.0	$(193.5)	$32.9	$45.1
Total fixed charges above	21.5	21.3	22.0	23.3	20.7
Pretax equity earnings of investees	(4.3)	(4.5)	(4.8)	(5.2)	(5.4)
Cash distributions from equity investees	4.7	4.9	5.0	8.2	2.7
Total Earnings (B)	$60.2	$71.7	$(171.3)	$59.2	$63.1
Ratio of Earnings to Fixed Charges (B/A)	2.80	3.37	(7.78)	2.54	3.05

For 2002, an additional $193.2 million in income before income taxes would be needed to obtain a ratio of 1.0. See Note 1G to the consolidated financial statements.

EXHIBIT 23.01

SCANA CORPORATION

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statements No. 333-18973, 333-37398, and 333-97555 of SCANA Corporation on Forms S-8 and Registration Statements No. 333-113749 and 333-68266 of SCANA Corporation on Forms S-3 of our reports dated February 28, 2005 relating to the financial statements and financial statement schedule of SCANA Corporation (which report expresses an unqualified opinion and includes an explanatory paragraph related to the adoption of Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets," effective January 1, 2002 as discussed in Note 1), and management's report on the effectiveness of internal control over financial reporting appearing in this Annual Report on Form 10-K of SCANA Corporation for the year ended December 31, 2004.

s/DELOITTE & TOUCHE LLP
Columbia, South Carolina
February 28, 2005

EXHIBIT 23.02

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-108760 of South Carolina Electric and Gas Company on Form S-3 of our report dated February 28, 2005 relating to the financial statements and financial statement schedule of South Carolina Electric & Gas Company appearing in this Annual Report on Form 10-K of South Carolina Electric and Gas Company for the year ended December 31, 2004.

s/DELOITTE & TOUCHE LLP
Columbia, South Carolina
February 28, 2005

EXHIBIT 23.03

PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INCORPORATED

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-68516 of Public Service Company of North Carolina, Incorporated on Form S-3 of our report dated February 28, 2005 relating to the financial statements and financial statement schedule of Public Service Company of North Carolina, Incorporated (which report expresses an unqualified opinion and includes an explanatory paragraph related to the adoption of Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets," effective January 1, 2002 as discussed in Note 1) appearing in this Annual Report on Form 10-K of Public Service Company of North Carolina, Incorporated for the year ended December 31, 2004.

s/DELOITTE & TOUCHE LLP
Columbia, South Carolina
February 28, 2005

Exhibit 24.01

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that each of the undersigned, being a director or officer of SCANA Corporation ("SCANA"), South Carolina Electric & Gas Company ("SCE&G") and Public Service Company of North Carolina, Incorporated ("PSNC"), hereby constitutes and appoints William B. Timmerman and Kevin B. Marsh, and each of them, his or her true and lawful attorney-in-fact and agent, with full power of substitution and resubstitution, for him or her and in his or her name, place and stead in any and all capacities, to sign one or more Annual Reports for SCANA's, SCE&G's and PSNC's fiscal year ended December 31, 2004, on Form 10-K under the Securities Exchange Act of 1934, as amended, or such other form as any such attorney-in-fact may deem necessary or desirable, any amendments thereto, each in such form as they or any one of them may approve, and to file the same with all exhibits thereto and other documents in connection therewith with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing requisite and necessary to be done so that such Annual Report shall comply with the Securities Exchange Act of 1934, as amended, and the applicable Rules and Regulations adopted or issued pursuant thereto, as fully and to all intents and purposes as he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them or their substitute or resubstitute, may lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, each of the undersigned has hereunto set his or her hand this 17th day of February 2005.

/s/ B. L. AMICK
B. L. Amick
Director

/s/ J. A. BENNETT
J. A. Bennett
Director

/s/ W. B. BOOKHART, JR.
W. B. Bookhart, Jr.
Director

/s/ W. C. BURKHARDT
W. C. Burkhardt
Director

/s/ E. T. FREEMAN
E. T. Freeman
Director

/s/ D. M. HAGOOD
D. M. Hagood
Director

/s/ W. H. HIPP
W. H. Hipp
Director

/s/ L. M. MILLER
L. M. Miller
Director

/s/ M. K. SLOAN
M. K. Sloan
Director

/s/ H. C. STOWE
H. C. Stowe
Director

/s/ W. B. TIMMERMAN
W. B. Timmerman
Director

/s/ G. S. YORK
G. S. York
Director

Exhibit 31.01

CERTIFICATION

I, William B. Timmerman, certify that:

1. I have reviewed this annual report on Form 10-K of SCANA Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent function):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2005

/s/ WILLIAM B. TIMMERMAN

William B. Timmerman
Chairman of the Board, President,
Chief Executive Officer and Director

Exhibit 31.02

CERTIFICATION

I, Kevin B. Marsh, certify that:

1. I have reviewed this annual report on Form 10-K of SCANA Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent function):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2005

/s/ KEVIN B. MARSH

Kevin B. Marsh
Senior Vice President and Chief Financial Officer

Exhibit 31.03

CERTIFICATION

I, William B. Timmerman, certify that:

1. I have reviewed this annual report on Form 10-K of South Carolina Electric & Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent function):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2005

/s/ WILLIAM B. TIMMERMAN

William B. Timmerman
Chairman of the Board, Chief Executive Officer and Director

Exhibit 31.04

CERTIFICATION

I, Kevin B. Marsh, certify that:

1. I have reviewed this annual report on Form 10-K of South Carolina Electric & Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent function):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2005

/s/ KEVIN B. MARSH

Kevin B. Marsh
Senior Vice President and Chief Financial Officer

Exhibit 31.05

CERTIFICATION

I, William B. Timmerman, certify that:

1. I have reviewed this annual report on Form 10-K of Public Service Company of North Carolina, Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

    (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    (b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    (c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent function):

    (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2005

/s/ WILLIAM B. TIMMERMAN

William B. Timmerman
Chairman of the Board, Chief Executive Officer and Director

Exhibit 31.06

CERTIFICATION

I, Kevin B. Marsh, certify that:

1. I have reviewed this annual report on Form 10-K of Public Service Company of North Carolina, Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent function):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2005

/s/ KEVIN B. MARSH

Kevin B. Marsh
Senior Vice President and Chief Financial Officer

Exhibit 32.01

SCANA CORPORATION

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of SCANA Corporation (the "Company") on Form 10-K for the year ended December 31, 2004 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I certify pursuant to 18 U.S.C. ss. 1350, as adopted pursuant to ss. 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: February 28, 2005

/s/ WILLIAM B. TIMMERMAN

William B. Timmerman
Chairman of the Board, President, Chief Executive Officer and Director

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.02

SCANA CORPORATION

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of SCANA Corporation (the "Company") on Form 10-K for the year ended December 31, 2004 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I certify pursuant to 18 U.S.C. ss. 1350, as adopted pursuant to ss. 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: February 28, 2005

/s/ KEVIN B. MARSH

Kevin B. Marsh
Senior Vice President and Chief Financial Officer

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.03

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of South Carolina Electric and Gas Company (the "Company") on Form 10-K for the year ended December 31, 2004 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I certify pursuant to 18 U.S.C. ss. 1350, as adopted pursuant to ss. 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: February 28, 2005

/s/ WILLIAM B. TIMMERMAN

William B. Timmerman
Chairman of the Board, Chief Executive Officer and Director

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.04

SOUTH CAROLINA ELECTRIC AND GAS COMPANY

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of South Carolina Electric and Gas Company (the "Company") on Form 10-K for the year ended December 31, 2004 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I certify pursuant to 18 U.S.C. ss. 1350, as adopted pursuant to ss. 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: February 28, 2005

/s/ KEVIN B. MARSH

Kevin B. Marsh
Senior Vice President and Chief Financial Officer

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.05

PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INCORPORATED

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Public Service Company of North Carolina, Incorporated (the "Company") on Form 10-K for the year ended December 31, 2004 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I certify pursuant to 18 U.S.C. ss. 1350, as adopted pursuant to ss. 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: February 28, 2005

/s/ WILLIAM B. TIMMERMAN

William B. Timmerman
Chairman of the Board, Chief Executive Officer and Director

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.06

PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INCORPORATED

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of Public Service Company of North Carolina, Incorporated (the "Company") on Form 10-K for the year ended December 31, 2004 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I certify pursuant to 18 U.S.C. ss. 1350, as adopted pursuant to ss. 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: February 28, 2005

/s/ KEVIN B. MARSH

Kevin B. Marsh
Senior Vice President and Chief Financial Officer

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.